UTILITY NO. 4220

Classes A and B

6031 (03-21-06)

ANNUAL REPORT

OF

Name: NORTHERN STATES POWER COMPANY (WISCONSIN)

Principal Office: 1414 W. HAMILTON AVENUE
P.O. BOX 8
EAU CLAIRE, WI 54702-0008

For the Year Ended: DECEMBER 31, 2005

WATER, ELECTRIC, OR JOINT UTILITY

TO

PUBLIC SERVICE COMMISSION OF WISCONSIN

P.O. Box 7854
Madison, WI 53707-7854
(608) 266-3766

This form is required under Wis. Stat. § 196.07. Failure to file the form by the statutory filing date can result in the imposition of a penalty under Wis. Stat. § 196.66. The penalty which can be imposed by this section of the statutes is a forfeiture of not less than $25 nor more than $5,000 for each violation. Each day subsequent to the filing date constitutes a separate and distinct violation. The filed form is available to the public and personally identifiable information may be used for purposes other than those related to public utility regulation.

GENERAL RULES FOR REPORTING

1. Prepare the report in conformity with the Uniform System of Accounts prescribed by the Public Service Commission of Wisconsin.

2. Numeric items shall contain digits (0-9). A minus sign "-" shall be entered in the software program to indicate negative values. Parentheses shall not be used for numeric items. The program will convert the minus sign to parentheses for hard copy annual report purposes. Negative values may not be allowed for certain entries in the annual report due to restrictions contained in the software program.

3. The annual report should be complete in itself in all particulars. Reference to reports of former years should not be made to take the place of required entries except as otherwise specifically authorized.

4. Whenever schedules call for data from the previous year, the data reported must be based upon those shown by the annual report of the previous year or an appropriate explanation given why different data is being reported for the current year. Where available, use an adjustment column.

5. All dollar amounts will be reported in thousands of whole dollars.

6. Wherever information is required to be shown as text, the information shall be shown in the space provided using other than account titles. In each case, the information shall be properly identified. Footnote capability is included in the annual report software program and shall be utilized where necessary to further explain particulars of a schedule.

SIGNATURE PAGE

I TERESA S. MADDEN of
(Person responsible for accounts)

NORTHERN STATES POWER COMPANY (WISCONSIN) , certify that I
(Utility Name)

am the person responsible for accounts; that I have examined the following report and, to the best of my knowledge, information and belief, it is a correct statement of the business and affairs of said utility for the period covered by the report in respect to each and every matter set forth therein.

/s/TERESA S. MADDEN
(Signature of person responsible for accounts)

05/15/2006
(Date)

VICE PRESIDENT AND CONTROLLER
(Title)

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

IDENTIFICATION AND OWNERSHIP

Exact Utility Name: NORTHERN STATES POWER COMPANY (WISCONSIN)
Utility Address: 1414 W. HAMILTON AVENUE
P.O. BOX 8
EAU CLAIRE, WI 54702-0008
When was utility organized? 11/21/1901
Previous name:
Date of change:
Utility Web Site: www.xcelenergy.com

Officer in charge of correspondence concerning this report:

Name: TERESA S. MADDEN
Title: VICE PRESIDENT AND CONTROLLER
Office Address:
414 NICOLLET MALL, SUITE 400
MINNEAPOLIS, MN 55401

Telephone: (612) 215 - 4560
Fax Number: (612) 215 - 4550
E-mail Address: teresa.s.madden@xcelenergy.com

Individual or firm, if other than utility employee, preparing this report:

Name:
Title:
Office Address:

Telephone:
Fax Number:
E-mail Address:

CONTROL OVER RESPONDENT

If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

100% of the voting stock of Northern States Power Company (Wisconsin) is held by Xcel Energy Inc., a publicly owned company. Northern States Power Company (Wisconsin) is a first tier subsidiary of Xcel Energy Inc.

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.
4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)		
Chippewa and Flambeau Improvement Company	Operate hydro reservoirs	76.00%	*	1
Clearwater Investments, Inc.	Affordable housing	100.00%		2
NSP Lands, Inc.	Real estate holdings	100.00%		3

CORPORATIONS CONTROLLED BY RESPONDENT

Corporations Controlled by Respondent (Page vi)

General footnotes

1. Northern States Power Company (Wisconsin) owns 76.41% of the outstanding shares of stock of Chippewa and Flambeau Improvement Company. Northern States Power Company (Wisconsin) ownership interest increased in 2005 as a result of Chippewa and Flambeau Improvement Company's repurchase in 2005 of 79 shares of stock owned by non-water power users. The repurchased shares are held as treasury stock of Chippewa and Flambeau Improvement Company per Wisconsin Statute 180.0631.

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Teresa S. Madden
Vice President and Controller

414 Nicollet Mall, Suite 400	1414 W. Hamilton Ave, P.O. Box 8
Minneapolis, MN 55401	Eau Claire, WI 54702-0008

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

The respondent was incorporated under the laws of the State of Wisconsin on November 21, 1901.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) the name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

During the year 2005, the respondent furnished electric utility and gas utility service in the states of Wisconsin and Michigan.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

○ Yes   If yes, enter the date when such independent accountant was initially engaged:

● No

OFFICERS' SALARIES

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Title (a)	Name of Officer (b)	Salary for Year (000's) (c)		
Chairman	Wayne H. Brunetti	0	*	1
Chairman	Richard C. Kelly	0	*	2
President and Chief Executive Officer	Michael L. Swenson	180		3
Vice President and General Counsel	Gary R. Johnson	0		4
Vice President	Paul J. Bonavia	0		5
Vice President	Raymond E. Gogel	0		6
Vice President	Cynthia L. Lesher	0		7
Vice President	Patricia K. Vincent	0		8
Vice President	David M. Wilks	0		9
Vice President and Chief Financial Officer	Benjamin G.S. Fowke III	0		10
Vice President and Treasurer	George E. Tyson II	0		11
Vice President and Controller	Teresa S. Madden	0		12
Vice President and Secretary	Cathy J. Hart	0		13

OFFICERS' SALARIES

Officers' Salaries (Page viii)

General footnotes

1. **Succeeded by Richard C. Kelly as Chairman on March 8, 2005.**

2. **Elected Chairman on March 8, 2005, succeeding Wayne H. Brunetti.**

OFFICERS

Name/Title and Principal Business Address (a)	Length Of Term (Years) (b)	Term Expires (c)	Meetings Attended (d)		
WAYNE H. BRUNETTI/CHAIRMAN 414 NICOLLET MALL MINNEAPOLIS, MN 55401	0	03/08/2005	0	*	1
RICHARD C. KELLY/CHAIRMAN 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	4	*	2
MICHAEL L. SWENSON/PRESIDENT AND CHIEF EXECUTIVE OFFICER 1414 W. HAMILTON AVE. EAU CLAIRE, WI 54701	1	09/20/2006	4		3
GARY R. JOHNSON/VICE PRESIDENT AND GENERAL COUNSEL 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	4		4
PAUL J. BONAVIA/VICE PRESIDENT 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	1		5
RAYMOND E. GOGEL/VICE PRESIDENT 550 15TH STREET DENVER, CO 80202	1	09/20/2006	0		6
CYNTHIA L. LESHER/VICE PRESIDENT 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	1		7
PATRICIA K. VINCENT/VICE PRESIDENT 1225 17TH STREET DENVER, CO 80202	1	09/20/2006	4		8
DAVID M. WILKS/VICE PRESIDENT 4653 TABLE MOUNTAIN DRIVE GOLDEN, CO 80403	1	09/20/2006	0		9

OFFICERS

Name/Title and Principal Business Address (a)	Length Of Term (Years) (b)	Term Expires (c)	Meetings Attended (d)	
BENJAMIN G.S. FOWKE III/VICE PRESIDENT AND CHIEF FINANCIAL OFFICER 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	3	**10**
GEORGE E. TYSON II/VICE PRESIDENT AND TREASURER 414 NICOLLET MALL, SUITE 400 MINNEAPOLIS, MN 55401	1	09/20/2006	0	**11**
TERESA S. MADDEN/VICE PRESIDENT AND CONTROLLER 414 NICOLLET MALL, SUITE 400 MINNEAPOLIS, MN 55401	1	09/20/2006	4	**12**
CATHY J. HART/VICE PRESIDENT AND SECRETARY 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	1	**13**

OFFICERS

Officers (Page ix)

General footnotes

1. **Succeeded by Richard C. Kelly as Chairman on March 8, 2005.**

2. **Elected Chairman on March 8, 2005, succeeding Wayne H. Brunetti.**

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Name/Title and Principal Business Address (a)	Length Of Term (Years) (b)	Term Expires (c)	Meetings Attended (d)		
MICHAEL L. SWENSON/PRESIDENT AND CHIEF EXECUTIVE OFFICER 1414 W. HAMILTON AVE. EAU CLAIRE, WI 54701	1	09/20/2006	4		1
WAYNE H. BRUNETTI/CHAIRMAN 414 NICOLLET MALL MINNEAPOLIS, MN 55401	0	03/08/2005	0	*	2
RICHARD C. KELLY/CHAIRMAN 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	4	*	3
BENJAMIN G.S. FOWKE III/VICE PRESIDENT AND CHIEF FINANCIAL OFFICER 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	3		4
GARY R. JOHNSON/VICE PRESIDENT AND GENERAL COUNSEL 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	4		5
PATRICIA K. VINCENT/VICE PRESIDENT 1225 17TH STREET DENVER, CO 80202	1	09/20/2006	4		6
PAUL J. BONAVIA/VICE PRESIDENT 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	1	*	7
CYNTHIA L. LESHER/VICE PRESIDENT 414 NICOLLET MALL MINNEAPOLIS, MN 55401	1	09/20/2006	1	*	8

DIRECTORS

Directors (Page x)

General footnotes

Northern States Power Company (Wisconsin)'s executive committee was rescinded by Board of Director resolution dated December 15, 2000.

2. Succeeded by Richard C. Kelly as Chairman on March 8, 2005.

3. Elected Chairman on March 8, 2005, succeeding Wayne H. Brunetti.

7. Elected to the Board of Directors on October 25, 2005.

8. Elected to the Board of Directors on October 25, 2005.

COMMON STOCKHOLDERS

From the stockholder list nearest the end of the year report the greatest of: 1) the ten largest shareholders of voting securities or 2) all shareholders owning 5% or more of voting securities. List names, addresses and shareholdings. If any stock is held by a nominee, give known particulars as to the beneficial owner (see Wis. Stat. § 196.795(1)(c), for definition of beneficial owner).

Date of stockholders' list nearest end of year: 12/31/2005

	Common	Preferred	Total
Number of stockholders on above date:	1		1
Number of shareholders in Wisconsin:	0		0
Percent of outstanding stock owned by Wisconsin Stockholders:	0.00%		

Stockholders:

Name: XCEL ENERGY INC. **1**
Address: 414 NICOLLET MALL
MINNEAPOLIS, MN 55401

Number of Shares Held:
Beneficial Owner:

INCOME STATEMENT

Particulars (a)	This Year (000's) (b)	Last Year (000's) (c)	
UTILITY OPERATING INCOME			
Operating Revenues (400)	584,825	522,032	**1**
Operating Expenses:			
Operating Expenses (401)	432,745	327,876	**2**
Maintenance Expenses (402)	18,613	21,207	**3**
Depreciation Expense (403)	45,698	44,454	**4**
Depreciation Expense for Asset Retirement Costs (403.1)			**5**
Amort. & Depl. Of Utility Plant (404-405)	5,533	2,548	**6**
Amort. Of Utility Plant Acq. Adj. (406)			**7**
Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)	(177)	(147)	**8**
Amort. Of Conversion Expenses (407.2)			**9**
Regulatory Debits (407.3)			**10**
Less: Regulatory Credits (407.4)			**11**
Taxes Other Than Income Taxes (408.1)	16,602	16,621	**12**
Income Taxes - Federal (409.1)	11,468	19,412	**13**
Income Taxes - Other (409.1)	2,794	8,267	**14**
Provision for Deferred Income Taxes (410.1)	34,939	22,267	**15**
Less: Provision for Deferred Income Taxes-Cr. (411.1)	32,274	14,206	**16**
Investment Tax Credit Adj. - Net (411.4)	(785)	(789)	**17**
Less: Gains from Disp. Of Utility Plant (411.6)			**18**
Losses from Disp. Of Utility Plant (411.7)			**19**
Less: Gains from Disposition of Allowances (411.8)			**20**
Losses from Disposition of Allowances (411.9)			**21**
Accretion Expense (411.10)			**22**
Total Utility Operating Expenses:	**535,156**	**447,510**	
Net Operating Income	**49,669**	**74,522**	
OTHER INCOME			
Revenues From Merchandising, Jobbing and Contract Work (415)	24	151	**23**
Less: Costs and Exp. Of Merchandising, Job. & Contract Work (416)	16	89	**24**
Revenues From Nonutility Operations (417)	22	8	**25**
Less: Expenses of Nonutility Operations (417.1)	33	84	**26**
Nonoperating Rental Income (418)	84	42	**27**
Equity in Earnings of Subsidiary Companies (418.1)	(59)	57	**28**
Interest and Dividend Income (419)	218	327	**29**
Allowance for Other Funds Used During Construction (419.1)	(159)	1,389	**30**
Miscellaneous Nonoperating Income (421)	684	611	**31**
Gain on Disposition of Property (421.1)	18	8	**32**
Total Other Income	**783**	**2,420**	
OTHER INCOME DEDUCTIONS			
Loss on Disposition of Property (421.2)	0	1	**33**
Miscellaneous Amortization (425)			**34**
Donations (426.1)	943	702	**35**
Life Insurance (426.2)	(105)	(67)	* **36**
Penalties (426.3)	1	0	**37**
Exp. For Certain Civic, Political & Related Activities (426.4)	446	447	**38**

INCOME STATEMENT

Particulars (a)	This Year (000's) (b)	Last Year (000's) (c)	
OTHER INCOME DEDUCTIONS			
Other Deductions (426.5)	504	401	**39**
Total Other Income Deductions	**1,789**	**1,484**	
TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS			
Taxes Other Than Income Taxes (408.2)	113	91	**40**
Income Taxes-Federal (409.2)	(1,116)	779	**41**
Income Taxes-Other (409.2)	(207)	73	**42**
Provision for Deferred Inc. Taxes (410.2)	337	85	**43**
Less: Provision for Deferred Inc. Taxes - Cr. (411.2)	24	469	**44**
Investment Tax Credit Adj.-Net (411.5)			**45**
Less: Investment Tax Credits (420)			**46**
Total Taxes Applicable to Other Income and Deductions	**(897)**	**559**	
Net Other Income and Deductions	**(109)**	**377**	
INTEREST CHARGES			
Interest on Long-Term Debt (427)	20,084	20,064	**47**
Amort. of Debt. Disc. And Expense (428)	259	258	**48**
Amortization of Loss on Reaquired Debt (428.1)	962	966	**49**
Less: Amort. of Premium on Debt-Credit (429)			**50**
Less: Amortization of Gain on Reaquired Debt-Credit (429.1)			**51**
Interest on Debt to Assoc. Companies (430)	1,369	362	**52**
Other Interest Expense (431)	446	(49)	**53**
Less: Allowance for Borrowed Funds Used During Construction-Cr. (432)	133	1,087	**54**
Total Interest Charges	**22,987**	**20,514**	
Income Before Extraordinary Items	**26,573**	**54,385**	
EXTRAORDINARY ITEMS			
Extraordinary Income (434)			**55**
Less: Extraordinary Deductions (435)			**56**
Net Extraordinary Items:	**0**	**0**	
Income Taxes-Federal and Other (409.3)			**57**
Extraordinary Items After Taxes	**0**	**0**	
Net Income	**26,573**	**54,385**	

INCOME STATEMENT

Income Statement (Page F-01)

General footnotes

36. Income on company owned life insurance.

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE

Particulars (a)	TOTAL This Year (000's) (b)	TOTAL Last Year (000's) (c)		
Operating Revenues (400)	584,825	522,032		1
Operating Expenses:				
Operating Expenses (401)	432,745	327,876		2
Maintenance Expenses (402)	18,613	21,207		3
Depreciation Expense (403)	45,698	44,454	*	4
Depreciation Expense for Asset Retirement Costs (403.1)	0	0		5
Amort. & Depl. Of Utility Plant (404-405)	5,533	2,548		6
Amort. Of Utility Plant Acq. Adj. (406)	0	0		7
Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)	(177)	(147)		8
Amort. Of Conversion Expenses (407.2)	0	0		9
Regulatory Debits (407.3)	0	0		10
Less: Regulatory Credits (407.4)	0	0		11
Taxes Other Than Income Taxes (408.1)	16,602	16,621		12
Income Taxes - Federal (409.1)	11,468	19,412		13
Income Taxes - Other (409.1)	2,794	8,267		14
Provision for Deferred Income Taxes (410.1)	34,939	22,267		15
Less: Provision for Deferred Income Taxes-Cr. (411.1)	32,274	14,206		16
Investment Tax Credit Adj. - Net (411.4)	(785)	(789)		17
Less: Gains from Disp. Of Utility Plant (411.6)	0	0		18
Losses from Disp. Of Utility Plant (411.7)	0	0		19
Less: Gains from Disposition of Allowances (411.8)	0	0		20
Losses from Disposition of Allowances (411.9)	0	0		21
Accretion Expense (411.10)	0	0		22
Total Utility Operating Expenses:	535,156	447,510		
Net Operating Income:	49,669	74,522		

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE (cont.)

Electric Utility		Gas Utility		Other Utility			
This Year (000's) (d)	**Last Year (000's) (e)**	**This Year (000's) (f)**	**Last Year (000's) (g)**	**This Year (000's) (h)**	**Last Year (000's) (i)**		
425,969	383,060	158,605	138,717	251	255		**1**
290,452	205,226	142,293	122,650	0	0		**2**
17,599	20,196	1,014	1,011	0	0		**3**
39,670	38,700	5,990	5,716	38	38	*	**4**
							5
4,885	2,231	648	317	0	0		**6**
							7
(177)	(147)	0	0	0	0		**8**
							9
							10
							11
14,686	14,771	1,916	1,850	0	0		**12**
11,605	19,821	(185)	(463)	48	54		**13**
2,776	7,726	11	533	7	8		**14**
27,023	17,560	7,924	4,715	(8)	(8)		**15**
26,048	11,342	6,226	2,864	0	0		**16**
(729)	(733)	(53)	(54)	(3)	(2)		**17**
							18
							19
							20
							21
							22
381,742	**314,009**	**153,332**	**133,411**	**82**	**90**		
44,227	**69,051**	**5,273**	**5,306**	**169**	**165**		

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE

Income Statement - Revenues & Expenses by Utility Type (Page F-02)

General footnotes

4. Other Utility depreciation expense represents expense of Plant Leased to Others.

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE (cont.)

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BALANCE SHEET

Assets and Other Debits (a)	Balance End of Year (000's) (b)	Balance First of Year (000's) (c)	
UTILITY PLANT			
Utility Plant (101-106, 114)	1,528,480	1,467,310	1
Construction Work in Progress (107)	10,435	20,141	2
Total Utility Plant:	**1,538,915**	**1,487,451**	
Less: Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	695,621	654,115	3
Net Utility Plant:	**843,294**	**833,336**	
Nuclear Fuel in Process of Ref., Conv.,Enrich.,and Fab. (120.1)			4
Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			5
Nuclear Fuel Assemblies in Reactor (120.3)			6
Spent Nuclear Fuel (120.4)			7
Nuclear Fuel Under Capital Leases (120.6)			8
Less: Accum. Prov. For Amort. Of Nucl. Fuel Assemblies (120.5)			9
Net Nuclear Fuel:	**0**		
Net Utility Plant:	**843,294**	**833,336**	
Utility Plant Adjustments (116)			10
Gas Stored Underground - Noncurrent (117)			11
OTHER PROPERTY AND INVESTMENTS			
Nonutility Property (121)	2,823	2,823	12
Less: Accum. Prov. for Depr. And Amort. (122)	56	56	13
Investments in Associated Companies (123)			14
Investments in Subsidiary Companies (123.1)	3,487	3,584	15
Noncurrent Portion of Allowances			16
Other Investments (124)	5,953	6,317	17
Sinking Funds (125)			18
Depreciation Fund (126)			19
Amortization Fund - Federal (127)			20
Other Special Funds (128)	135	0	21
Long-Term Portion of Derivative Assets (175)			22
Long-Term Portion of Derivative Assets - Hedges (176)	0	0	23
Total Other Property and Investments	**12,342**	**12,668**	
CURRENT AND ACCRUED ASSETS			
Cash (131)			24
Special Deposits (132-134)			25
Working Fund (135)	100	101	26
Temporary Cash Investments (136)			27
Notes Receivable (141)			28
Customer Accounts Receivable (142)	61,160	48,060	29
Other Accounts Receivable (143)	1,955	4,521	30
Less: Accum. Prov. For Uncollectible Acct.-Credit (144)	1,461	1,258	31
Notes Receivable from Associated Companies (145)			32
Accounts Receivable from Assoc. Companies (146)	10,132	1,154	33
Fuel Stock (151)	8,619	6,317	34
Fuel Stock Expenses Undistributed (152)			35
Residuals (Elec) and Extracted Products (153)			36
Plant Materials and Operating Supplies (154)	4,973	4,690	37
Merchandise (155)	3	19	38
Other Materials and Supplies (156)			39
Nuclear Materials Held for Sale (157)			40

BALANCE SHEET

Assets and Other Debits (a)	Balance End of Year (000's) (b)	Balance First of Year (000's) (c)	
CURRENT AND ACCRUED ASSETS			
Allowances (158.1 and 158.2)			41
Less: Noncurrent Portion of Allowances			42
Stores Expense Undistributed (163)	0	0	43
Gas Stored Underground - Current (164.1)	14,235	9,187	44
Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	263	37	45
Prepayments (165)	16,860	16,452	46
Advances for Gas (166-167)			47
Interest and Dividends Receivable (171)			48
Rents Receivable (172)	0	0	49
Accrued Utility Revenues (173)	39,925	27,664	50
Miscellaneous Current and Accrued Assets (174)			51
Derivative Instrument Assets (175)			52
(Less) Long-Term Portion of Derivative Instrument Assets (175)			53
Derivative Instrument Assets - Hedges (176)	3,798	1,405	54
(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)	0	0	55
Total Current and Accrued Assets	**160,562**	**118,349**	
DEFERRED DEBITS			
Unamortized Debt Expenses (181)	1,850	2,036	56
Extraordinary Property Losses (182.1)			57
Unrecovered Plant and Regulatory Study Costs (182.2)			58
Other Regulatory Assets (182.3)	49,783	38,123	59
Prelim. Survey and Investigation Charges (Electric) (183)	1,090	1,090	60
Preliminary Natural Gas Survey and Investigation Charges (183.1)			61
Other Preliminary Survey and Investigation Charges (183.2)			62
Clearing Accounts (184)			63
Temporary Facilities (185)			64
Miscellaneous Deferred Debits (186)	59,117	56,806	65
Def. Losses from Disposition of Utility Plt. (187)			66
Research, Devel. And Demonstration Expend. (188)			67
Unamortized Loss on Reaquired Debt (189)	11,675	12,638	68
Accumulated Deferred Income Taxes (190)	45,728	43,419	69
Unrecovered Purchased Gas Costs (191)	124	0	70
Total Deferred Debits	**169,367**	**154,112**	
Total Assets and Other Debits	**1,185,565**	**1,118,465**	

BALANCE SHEET

Liabilities and Other Credits (a)	Balance End of Year (000's) (b)	Balance First of Year (000's) (c)	
PROPRIETARY CAPITAL			
Common Stock Issued (201)	93,300	93,300	**71**
Preferred Stock Issued (204)			**72**
Capital Stock Subscribed (202, 205)			**73**
Stock Liability for Conversion (203, 206)			**74**
Premium on Capital Stock (207)	33,337	33,337	**75**
Other Paid-In Capital (208-211)	54,469	31,939	**76**
Installments Received on Capital Stock (212)			**77**
(Less) Discount on Capital Stock (213)			**78**
(Less) Capital Stock Expense (214)			**79**
Retained Earnings (215, 215.1, 216)	254,608	272,257	**80**
Unappropriated Undistributed Subsidiary Earnings (216.1)	2,738	2,835	**81**
Less: Reaquired Capital Stock (217)			**82**
Accumulated Other Comprehensive Income (219)	(969)	(1,046)	**83**
Total Proprietary Capital	**437,483**	**432,622**	
LONG-TERM DEBT			
Bonds (221)	215,000	215,000	**84**
(Less) Reaquired Bonds (222)			**85**
Advances from Associated Companies (223)			**86**
Other Long-Term Debt (224)	99,428	99,461	**87**
Unamortized Premium on Long-Term Debt (225)			**88**
(Less) Unamortized Discount on Long-Term Debt-Debit (226)	919	985	**89**
Total Long-Term Debt	**313,509**	**313,476**	
OTHER NONCURRENT LIABILITIES			
Obligations Under Capital Leases - Noncurrent (227)			**90**
Accumulated Provision for Property Insurance (228.1)			**91**
Accumulated Provision for Injuries and Damages (228.2)	850	1,458	**92**
Accumulated Provision for Pensions and Benefits (228.3)	1,527	1,576	**93**
Accumulated Miscellaneous Operating Provisions (228.4)	711	351	**94**
Accumulated Provision for Rate Refunds (229)			**95**
Long-Term Portion of Derivative Instrument Liabilities (244)			**96**
Long-Term Portion of Derivative Instrument Liabilities - Hedges (245)	0	0	**97**
Asset Retirement Obligations (230)	2,936	0	**98**
Total Other Noncurrent Liabilities	**6,024**	**3,385**	
CURRENT AND ACCRUED LIABILITIES			
Notes Payable (231)			**99**
Accounts Payable (232)	43,615	30,900	**100**
Notes Payable to Associated Companies (233)	64,000	31,500	**101**
Accounts Payable to Associated Companies (234)	16,320	9,565	**102**
Customer Deposits (235)	1,755	1,712	**103**
Taxes Accrued (236)	4,032	901	**104**
Interest Accrued (237)	4,093	4,265	**105**
Dividends Declared (238)	10,597	11,961	**106**
Matured Long-Term Debt (239)			**107**
Matured Interest (240)			**108**
Tax Collections Payable (241)	1,531	1,353	**109**
Miscellaneous Current and Accrued Liabilities (242)	2,713	2,953	**110**
Obligations Under Capital Leases-Current (243)			**111**
Derivative Instrument Liabilities (244)			**112**

BALANCE SHEET

Liabilities and Other Credits (a)	Balance End of Year (000's) (b)	Balance First of Year (000's) (c)	
CURRENT AND ACCRUED LIABILITIES			
(Less) Long-Term Portion of Derivative Instrument Liabilities (244)			**113**
Derivative Instrument Liabilities - Hedges (245)	718	1,060	**114**
(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges (245)	0	0	**115**
Total Current and Accrued Liabilities	**149,374**	**96,170**	
DEFERRED CREDITS			
Customer Advances for Construction (252)	17,734	16,912	**116**
Accumulated Deferred Investment Tax Credits (255)	12,451	13,237	**117**
Deferred Gains from Disposition of Utility Plant (256)			**118**
Other Deferred Credits (253)	24,063	20,985	**119**
Other Regulatory Liabilities (254)	10,225	12,890	**120**
Unamortized Gain on Reaquired Debt (257)			**121**
Accumulated Deferred Income Taxes-Accel. Amort. (281)	17	48	**122**
Accumulated Deferred Income Taxes-Other Property (282)	165,720	165,250	**123**
Accumulated Deferred Income Taxes-Other (283)	48,965	43,490	**124**
Total Deferred Credits	**279,175**	**272,812**	
Total Liabilities and Other Credits	**1,185,565**	**1,118,465**	

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.

   None

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particluars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.

   None

3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.

   None

4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.

   None

5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to such arrangements, etc.

   None

6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity date of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.

   Notes 2 and 3 to the Financial Statements contain information on the short-term borrowings and long-term debt, respectively. Short-term borrowings are authorized by the Public Service Commission of Wisconsin (PSCW) Certificate of Authority and Order in Docket Nos. 4220-SB-123 and 4220-AU-130. In this Certificate of Authority and Order (effective Dec. 23, 2005), the PSCW increased NSP-Wisconsin's short-term borrowing limit from $50 million to $75 million. Note 7 to the Financial Statements contains information on carrying amount and fair value of long term debt, guarantees, and letters of credit outstanding.

7. Changes in articles of incorporation or amendments to charter. Explain the nature and purpose of such changes or amendments.

   None

8. State the estimated annual effect and nature of any important wage scale changes during the year.

   Bargaining employees received a 3.0 percent base wage increase effective Jan. 1, 2005. The average 2005 non-bargaining merit base increase across all companies of Xcel Energy, which includes NSP-Wisconsin, was 3.0 percent effective Mar. 1, 2005.

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings completed during the year.

Pending Legal Proceedings:

Stray Voltage

On Nov. 13, 2001, Ralph and Karline Schmidt filed a complaint in Clark County, Wisconsin against NSP-Wisconsin. Plaintiffs allege that electricity provided by NSP-Wisconsin harmed their dairy herd resulting in decreased milk production, lost profits and income, property damage and seek compensatory, punitive and treble damages. Plaintiffs allege compensatory damages of $1.0 million and pre-verdict interest of $1.2 million. In addition, plaintiffs allege an unspecified amount of damages related to nuisance. On March 21, 2005 the trial court granted NSP-Wisconsin's summary judgment motion on the bases of the statute of limitations and the filed doctrine. Plaintiffs' appeal is pending in District IV, Court of Appeals.

On Nov. 13, 2001, August C. Heeg Jr. and Joanne Heeg filed a complaint in Clark County, Wisconsin against NSP-Wisconsin. Plaintiffs allege that electricity provided by NSP-Wisconsin harmed their dairy herd resulting in decreased milk production, lost profits and income, property damage and seek compensatory, punitive and treble damages. Plaintiffs allege compensatory damages of $1.9 million and pre-verdict interest of $6.1 million. In addition, plaintiffs allege an unspecified amount of damages related to nuisance. On Feb. 7, 2005, the trial court granted NSP-Wisconsin's motion for summary judgment based upon the statute of limitations. On reconsideration, the trial court on March 21, 2005, upheld its prior grant of summary judgment based upon the statute of limitations and also added the filed rate doctrine as a basis for summary judgment. Plaintiffs' appeal is pending in District IV, Court of Appeals.

On March 1, 2002, NSP-Wisconsin was served with a lawsuit commenced by James and Grace Gumz and Michael and Susan Gumz in Marathon County Circuit Court, Wisconsin, alleging that electricity supplied by NSP-Wisconsin harmed their dairy herd and caused them personal injury. In 2004, the trial court granted partial summary judgment to NSP-Wisconsin, dismissing plaintiff's claims for strict products liability, trespass, pre-verdict interest, personal injury and treble damage claims. As a result of these rulings and some modifications by the plaintiffs in their damage calculations, the plaintiffs' alleged compensatory damages have been reduced to approximately $901,000 and an unspecified amount for nuisance. On March 4, 2005, a verdict in the amount of approximately $533,000 was returned against NSP-Wisconsin. On April 12, 2005, the trial court denied plaintiffs' and NSP-Wisconsin's motions after verdict and entered judgment on the verdict. In May 2005, NSP-Wisconsin appealed the trial court judgment. Plaintiffs have filed a cross-appeal with respect to the trial court's dismissal of the treble damages claim. The appeal is pending in District III, Court of Appeals.

Manufactured Gas Plant Insurance Coverage Litigation:

In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire, and LaCrosse, Wis. In lieu of participating in discussions, on Oct. 28, 2003, two of NSP-Wisconsin's insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. On Nov. 12, 2003, NSP-Wisconsin commenced suit in Wisconsin state circuit court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Wisconsin court denied the insurers' motion to stay the Wisconsin case pending resolution of the Minnesota action. On Jan. 6, 2005, the Minnesota court issued an injunction prohibiting NSP-Wisconsin from prosecuting the Wisconsin action. The injunction was stayed pending appeal. On Dec. 27, 2005, the Minnesota Court of Appeals upheld the issuance of the anti-suit injunction. On Jan. 26, 2006, NSP-Wisconsin submitted for filing its petition for review with the Minnesota Supreme Court. On Jan. 13, 2006, the Minnesota trial court extended its stay of the anti-suit injunction until Feb. 28, 2006, or until the Minnesota Supreme Court denies NSP-Wisconsin's petition for review, whichever occurs first. If the petition for review is accepted after February 28, 2006, the parties may seek leave to re-instate the stay. Trial in the Minnesota action is scheduled to commence on Nov. 6, 2006. A status conference in the Wisconsin action is scheduled for Feb. 23, 2006. Trial in the Wisconsin action is scheduled to begin in January 2007.

On Jan. 10, 2006, NSP-Wisconsin, entered into a confidential settlement agreement with St. Paul Mercury Insurance Company, St. Paul Fire and Marine Insurance Company and The Phoenix Insurance Company (St. Paul Companies), and the St. Paul Companies have been dismissed from the Minnesota and Wisconsin actions. The settlement with the St. Paul Companies will not have a material effect on NSP-Wisconsin financial results.

On Feb. 10, 2006, NSP-Wisconsin filed with the Minnesota court a renewed motion for dismissal under the doctrine of forum non conveniens and a motion for dissolution of the anti-suit injunction. These motions were based upon the changed circumstances resulting from the dismissal of the St. Paul Companies. The St. Paul Companies were the only Minnesota-based insurers and provided what the trial court viewed as a crucial Minnesota connection supporting its issuance of the anti-suit injunction and denial of NSP-Wisconsin's February 2004 motion to dismiss under the doctrine of forum non conveniens. These motions are currently set for hearing on March 13, 2006.

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will operate as a credit to ratepayers, therefore, these lawsuits should not have an impact on shareholders, and no accruals have been made.

See Note 8 to the Financial Statements for additional discussion of legal actions against

IMPORTANT CHANGES DURING THE YEAR

See Note 8 to the Financial Statements for additional discussion of legal contingencies.

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise.

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.

None

11. (Reserved)

Not Applicable

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page or in the Appendix.

None

13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.

The following changes were made in 2005 to the Officers and Board of Directors.

Officers:
Richard C. Kelly resigned his position as Vice President on Mar. 8, 2005.

Board of Directors:
Wayne H. Brunetti resigned as Director and Chairman of the Board of Directors on Mar. 8, 2005.
Richard C. Kelly was elected Chairman of the Board of Directors on Mar. 8, 2005 succeeding Wayne H. Brunetti.
Paul J. Bonavia was elected to the Board of Directors on Oct. 25, 2005.
Cynthia L. Lesher was elected to the Board of Directors on Oct. 25, 2005.

There were no changes in 2005 to the security holders and voting powers of NSP-Wisconsin. All shares of NSP-Wisconsin continue to be owned by Xcel Energy Inc. (a Minnesota corporation).

14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary capital ratio.

NSP-Wisconsin's equity ratio is greater than 30 percent; therefore, this item is not applicable.

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Description (a)	Amount (000's) (b)		
Net Cash Flow from Operating Activities:			1
Net Income	26,573		2
Noncash Charges (Credits) to Income:			3
Depreciation and Depletion	51,055		4
Amortization	1,221	*	5
			6
			7
Deferred Income Taxes (Net)	2,978		8
Investment Tax Credit Adjustment (Net)	(785)		9
Net (Increase) Decrease in Receivables	(19,307)		10
Net (Increase) Decrease in Inventory	(7,843)		11
Net (Increase) Decrease in Allowances Inventory	0		12
Net Increase (Decrease) in Payables and Accrued Expenses	22,606		13
Net (Increase) Decrease in Other Regulatory Assets	(11,957)		14
Net (Increase) Decrease in Other Regulatory Liabilities	(1,916)		15
(Less) Allowance for Other Funds Used During Construction	(159)		16
(Less) Undistributed Earnings from Subsidiary Companies	(97)		17
Other (provide details in footnote):			18
(Increase) Decrease in Accrued Utility Revenues	(12,261)		19
Miscellaneous Changes in Working Capital	(3,341)		20
Changes in Other Assets and Liabilities	1,251		21
Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	**48,530**		22
			23
Cash Flows from Investment Activities:			24
Construction and Acquisition of Plant (including land):			25
Gross Additions to Utility Plant (less nuclear fuel)	(57,916)		26
Gross Additions to Nuclear Fuel	0		27
Gross Additions to Common Utility Plant	0		28
Gross Additions to Nonutility Plant	0		29
(Less) Allowance for Other Funds Used During Construction	159		30
Other (provide details in footnote):			31
			32
			33
Cash Outflows for Plant (Total of lines 26 thru 33)	**(58,075)**		34
			35
Acquisition of Other Noncurrent Assets (d)	0		36
Proceeds from Disposal of Noncurrent Assets (d)	0		37
			38

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Description (a)	Amount (000's) (b)		
Investments in and Advances to Assoc. and Subsidiary Companies	0		39
Contributions and Advances from Assoc. and Subsidiary Companies	32,500		40
Disposition of Investments in (and Advances to)			41
Associated and Subsidiary Companies	0		42
			43
Purchase of Investment Securities (a)	0		44
Proceeds from Sales of Investment Securities (a)	0		45
Loans Made or Purchased	0		46
Collections on Loans	0		47
			48
Net (Increase) Decrease in Receivables	0		49
Net (Increase) Decrease in Inventory	0		50
Net (Increase) Decrease in Allowances Held for Speculation	0		51
Net Increase (Decrease) in Payables and Accrued Expenses	0		52
Other (provide details in footnote):	230	*	53
			54
			55
Net Cash Provided by (Used in) Investing Activities			56
Total of lines 34 thru 55)	**(25,345)**		57
			58
Cash Flows from Financing Activities:			59
Proceeds from Issuance of:			60
Long-Term Debt (b)	0		61
Preferred Stock	0		62
Common Stock	0		63
Other (provide details in footnote):	22,530	*	64
			65
Net Increase in Short-Term Debt (c)	0		66
Other (provide details in footnote):			67
			68
			69
Cash Provided by Outside Sources (Total 61 thru 69)	**22,530**		70
			71
Payments for Retirement of:			72
Long-term Debt (b)	(34)		73
Preferred Stock	0		74
Common Stock	0		75
Other (provide details in footnote):			76
			77

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Description (a)	Amount (000's) (b)	
Net Decrease in Short-Term Debt (c)	0	**78**
		79
Dividends on Preferred Stock	0	**80**
Dividends on Common Stock	(45,682)	**81**
Net Cash Provided by (Used in) Financing Activities		**82**
(Total of lines 70 thru 81)	**(23,186)**	**83**
		84
Net Increase (Decrease) in Cash and Cash Equivalents		**85**
(Total of lines 22, 57 and 83)	**(1)**	**86**
		87
Cash and Cash Equivalents at Beginning of Year	101	**88**
		89
Cash and Cash Equivalents at End of Year	100	**90**

STATEMENT OF CASH FLOWS

Statement of Cash Flows (Page F-06)

General footnotes

5. Amortization of premium, discount and debt expense

53. Miscellaneous Other Investing Activities

64. Capital Contribution by Parent

RETURN ON COMMON EQUITY AND COMMON STOCK EQUITY PLUS ITC COMPUTATIONS

1. Report data on a corporate basis only; not a consolidated basis.
2. If you file monthly rate of return forms with the PSC, use the same method for completing this form.
3. Use the average of the 12 monthly averages when computing average common equity.
4. If monthly averages are not available, use average of first of year and end of year.

Description (a)		Common Equity (000's) (b)	Common Equity Plus ITC (000's) (c)	
Average Common Equity				
Common Stock Outstanding		93,300	93,300	**1**
Premium on Capital Stock	based on monthly	33,337	33,337	**2**
Capital Stock Expense	averages if available			**3**
Retained Earnings		244,871	244,871	**4**
Deferred Investment Tax Credit			6,871	**5**
(Only common equity portion if Form PSC-AF6 is filed on monthly basis with the Commission)				
Other (Specify):				
Paid in Capital		52,796	52,796	**6**
Average Common Stock Equity		424,304	431,175	
Net Income				
Add:				
Net Income (or Loss)		26,573	26,573	**7**
Other (Specify):				
NONE				**8**
Less:				
Preferred Dividends			332	**9**
Other (Specify):				
(If Form PSC-AF6 is filed with the Commission, net income must be reduced by that portion of net income representing debt cost of deferred investment tax credit as shown on the form.)				
NONE				**10**
Adjusted Net Income (Loss)		26,573	26,241	
Percent Return on Common Stock Equity		**6.26%**	**6.09%**	

RETURN ON RATE BASE COMPUTATION

1. Report data on a corporate basis only; not a consolidated basis.
2. The data used in calculating average rate base are based on monthly averages, if available.
3. If you file monthly rate of return forms (PSC-AF4) with the PSC, use the same method for completing this schedule.
4. If monthly averages are not available, use average of the first-of-year and the end-of-year figures for each account.
5. Do not include property held for future use or construction work in progress with utility plant in service. These are not rate base components.

Average Rate Base (a)	Electric (000's) (b)	Gas (000's) (c)	Water (000's) (d)	Other (000's) (e)	Total (000's) (f)	
Add Average:						
Utility Plant in Service	1,246,829	149,405			**1,396,234**	**1**
Allocation of Common Plant	82,899	18,445			**101,344**	**2**
Completed Construction Not Classified					**0**	**3**
Gas Stored Underground		8,369			**8,369**	**4**
Nuclear Fuel					**0**	**5**
Materials and Supplies	10,911	1,010			**11,921**	**6**
Other (Specify):						
INVEST IN CHIP. FLAM. IMPR. CO.	23				**23**	**7**
REGULATORY ASSET	2,919	557			**3,476**	**8**
Less Average:						
Reserve for Depreciation	591,498	86,485			**677,983**	**9**
Amortization Reserves	1,834				**1,834**	**10**
Customer Advances for Construction	14,980	2,515			**17,495**	**11**
Contribution in Aid of Construction					**0**	**12**
Accumulated Deferred Income Taxes	110,432	5,376			**115,808**	**13**
Other (Specify):						
APPROP. RETAINED EARNINGS	11,494				**11,494**	**14**
Average Net Rate Base	**613,343**	**83,410**	**0**	**0**	**696,753**	
Total Operating Income (or Loss)	44,227	5,273	0		**49,500**	**15**
Less (Specify):						
NONE					**0**	**16**
Adjusted Operating Income	**44,227**	**5,273**	**0**	**0**	**49,500**	
Adjusted Operating Income as a percent of Average Net Rate Base	**7.21%**	**6.32%**	**N/A**	**N/A**	**7.10%**	

REVENUES SUBJECT TO WISCONSIN REMAINDER ASSESSMENT

1. Report data necessary to calculate revenue subject to Wisconsin remainder assessment.
2. For purposes of this schedule "out-of-state" and "in-state" refer to the geographic state of Wisconsin.

Description (a)	Electric Utility (000's) (b)	Gas Utility (000's) (c)	Water Utility (000's) (d)	Other Utility (000's) (e)	Total (000's) (f)	
Operating revenues	425,969	158,605	0		**584,574**	**1**
Less: out-of-state operating revenues					**0**	**2**
Less: in-state interdepartmental sales	207	2,012			**2,219**	**3**
Less: current year write-offs of uncollectible accounts (Wisconsin utility customers only)	1,991	676			**2,667**	**4**
Plus: current year collection of Wisconsin utility customer accounts previously written off	895	281			**1,176**	**5**
Other Increases or (Decreases) to Operating Revenues - Specify: NONE					**0**	**6**
Revenues subject to Wisconsin Remainder Assessment	**424,666**	**156,198**	**0**	**0**	**580,864**	

AFFILIATED INTEREST TRANSACTIONS

Intercompany Transactions from utility to Associated Companies

Department (a)	Hours Paid (b)	Total Costs (including Overheads) (000's) (c)	Total Billing (000's) (d)	Markup for Fair Market Value (000's) (e)	
Labor					
Corporate Affairs				0	1
Corporate Center				0	2
Commodity Resources				0	3
Customer Relations				0	4
Communications				0	5
Electric Operations				0	6
Environmental				0	7
Finance				0	8
Fossil Operations				0	9
Governmental Affairs				0	10
Human Resources				0	11
Information Resources				0	12
Legal Services				0	13
Regulatory Affairs				0	14
Supply Chain				0	15
				0	16
				0	17
				0	18
				0	19
				0	20
				0	21
Total Labor	0	0	0	0	
Other					
In-house Printing				0	22
Postage				0	23
Catering				0	24
Vouchers				0	25
Personal Auto				0	26
Company Vehicles				0	27
Rent				0	28
Information Resources				0	29
Materials and Supplies				0	30
				0	31
				0	32
				0	33
				0	34
				0	35
				0	36
Total Other	0	0	0	0	
Total:	0	0	0	0	

AFFILIATED INTEREST TRANSACTIONS

Affiliated Interest Transactions (Page F-10)

General footnotes

Detail was not obtained at this level for the 2005 reporting year. See appendix for Affiliated Interest Transaction reporting similar to prior years.

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Classification (a)	Total (000's) (b)	Electric (000's) (c)	
Utility Plant			1
In Service			2
Plant in Service (Classified)	**1,525,615**	1,264,926	3
Property Under Capital Leases	**0**	0	4
Plant Purchased or Sold	**0**	0	5
Completed Construction not Classified	**0**	0	6
Experimental Plant Unclassified	**0**	0	7
Total In Service	**1,525,615**	**1,264,926**	8
Leased to Others		2,832	9
Held for Future Use	**34**	34	10
Construction Work in Progress	**10,435**	7,458	11
Acquisition Adjustments	**0**	0	12
Total Utility Plant	**1,538,915**	**1,275,249** *	13
Accum Prov for Depr, Amort, & Depl	**695,621**	567,093	14
Net Utility Plant	**843,294**	**708,156**	15
Detail of Accum Prov for Depr, Amort, & Depl			16
In Service:			17
Depreciation	**692,919**	564,391	18
Amort & Depl of Producing Nat Gas Land/land Right	**0**		19
Amort of Underground Storage Land/Land Rights	**0**		20
Amort of Other Utility Plant	**1,883**	1,883	21
Total In Service	**694,802**	**566,274**	22
Leased to Others			23
Depreciation	**820**	820	24
Amortization and Depletion	**0**	0	25
Total Leased to Others	**820**	**820**	26
Held for Future Use			27
Depreciation	**0**	0	28
Amortization	**0**	0	29
Total Held for Future Use	**0**	**0**	30
Abandonment of Leases (Natural Gas)	**0**	0	31
Amort of Plant Acquisition Adj	**0**	0	32
Total Accum Prov	**695,621**	**567,093**	33

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (cont.)

Gas (000's) (d)	Other (Specify) (000's) (e)	Other (Specify) (000's) (f)	Other (Specify) (000's) (g)	Common (000's) (h)	
					1
					2
155,628	0	0	0	105,061	3
0	0	0	0	0	4
0	0	0	0	0	5
0	0	0	0	0	6
0	0	0	0	0	7
155,628	**0**	**0**	**0**	**105,061**	8
0	0	0	0	0	9
0	0	0	0	0	10
883	0	0	0	2,094	11
0	0	0	0	0	12
156,511	**0**	**0**	**0**	**107,155** *	13
80,155	0	0	0	48,373	14
76,356	**0**	**0**	**0**	**58,782**	15
					16
					17
80,155	0	0	0	48,373	18
0					19
0					20
0	0	0	0	0	21
80,155	**0**	**0**	**0**	**48,373**	22
					23
0	0	0	0	0	24
0	0	0	0	0	25
0	**0**	**0**	**0**	**0**	26
					27
0	0	0	0	0	28
0	0	0	0	0	29
0	**0**	**0**	**0**	**0**	30
0	0	0	0	0	31
0	0	0	0	0	32
80,155	**0**	**0**	**0**	**48,373**	33

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (Page F-11)

General footnotes

Note: The Electric Plant Leased to Others total automatically comes through on this page, but does not show up on that line in the Total column, however is included in the Total Utility Plant total in the Total column.

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (cont.)

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UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)

Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to Be Used in Utility Service (c)	Balance at End of Year (000's) (d)	
Land and Rights:				
Various			34	**1**
Other Property:			0	**2**
Other Property:				
TOTAL				**3**
Total			**34**	

CONSTRUCTION WORK IN PROGRESS (ACCT. 107)

1. Report below descriptions and balances at beginning and end of year of projects in process of construction (107).
2. Minor projects under $1,000,000 major and under $500,000 nonmajor should be grouped by utility department and function.

Project Description (a)	Balance First of Year (000's) (b)	Balance End of Year (000's) (c)	
Electric			
Minor Projects		4,193	**1**
3101 WI 345 kv King Eau Claire Total		3,707	**2**
3449 Marshland to Winona-Str Total		2,764	**3**
New Stanley Area Substation Total		1,194	**4**
SCF No. 3 Hydro Turbine Replace Total		787	**5**
WI Major Storm Recovery Blanket Total		519	**6**
3102 WI 345 kv Eau Claire - Arp Total		507	**7**
N-O substation metering/SCADA Total		505	**8**
Transmission Line 2004 Capital Total		365	**9**
DLL Dells Hydro Repowering Total		357	**10**
2004 NSPW Tran Line Blanket Total		348	**11**
2005 NSPW Tran Line Blanket Total		287	**12**
WI Rural Upgrades Total		268	**13**
NSP Blanket Relocations-WI Total		188	**14**
3483-Relocate EC-Otter Creek F Total		167	**15**
Withee Sub Cap Bank Trans Total		167	**16**
ES Doc Mgmt Online Proj Mgmt WI Total		112	**17**
WI-Worst Performing Feeder Total		107	**18**
WI-Elec Non-Refundable CIAC Total		(9,084)	* **19**
Subtotal - Electric:	**0**	**7,458**	
Gas			
Minor Projects		883	**20**
Subtotal - Gas:	**0**	**883**	
Water			
NONE			**21**
Subtotal - Water:	**0**	**0**	
Steam			
NONE			**22**
Subtotal - Steam:	**0**	**0**	
Common			
Minor Projects		2,094	**23**
Subtotal - Unknown:	**0**	**2,094**	
Other			
NONE			**24**
Subtotal - Other:	**0**	**0**	
Total:	**0**	**10,435**	

CONSTRUCTION WORK IN PROGRESS (ACCT. 107)

Construction Work in Progress (Acct. 107) (Page F-14)

General footnotes

19. Projects with negative balances are generally attributable to customer payments received in advance of construction or timing differences on the distribution of overheads.

CONSTRUCTION ACTIVITY FOR YEAR

Report below the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (000's) (b)	Company Materials (000's) (c)	Contractor Payments (000's) (d)	Other (000's) (e)	
Electric					
Projects over $1,000,000					**1**
Electric Production	0	0	0	0	**2**
French Island Units 1 & 2 Baghouse	0	0	(8)	0	**3**
French Island Steam 1 & 2 Baghouse	0	0	0	54	**4**
Bay Front #1 Asbestos Removal	3	5	409	0	**5**
Bay Front #2 Asbestos Removal		0	0	0	**6**
St Croix Falls Hydro - Automation	44	9	0	6	**7**
Electric Transmission	0	0	0	0	**8**
T-Corners Substation Replace Transfomer	322	792	116	72	**9**
T-Corners Substaton - Install Cap Banks		0	0	0	**10**
3449 Marshland Winona Structure	94	245	1,963	36	**11**
3101 WI 345KV King-Eau Claire Line	562	2,222	502	195	**12**
Distribution	0	0	0	0	**13**
Stanley Area Substation	81	655	110	12	**14**
	0	0	0	0	**15**
Projects under $1,000,000	6,271	13,042	7,154	159	**16**
Subtotal Electric:	**7,377**	**16,970**	**10,246**	**534**	
% of Subtotal Direct Charges:					
Gas					
Projects under $1,000,000	1,064	1,418	1,413	894	**17**
Subtotal Gas:	**1,064**	**1,418**	**1,413**	**894**	
% of Subtotal Direct Charges:					
Water					
NONE					**18**
Subtotal Water:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Steam					
NONE					**19**
Subtotal Steam:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Common					
Projects over $1,000,000					**20**
SS Western Ave Warehouse Expansion	45	5	166	0	**21**
COS DAMS One OMS	9	0	178	3	**22**
CRS Customer Resource System P3 WI	40	0	796	5	**23**
	0	0	0	0	**24**
Projects under $1,000,000	245	1,177	3,497	45	**25**
Subtotal Common:	**339**	**1,182**	**4,637**	**53**	
% of Subtotal Direct Charges:					

CONSTRUCTION ACTIVITY FOR YEAR (cont.)

Total Direct Charges (000's) (f)	Overheads: Engineering & Supervision (000's) (g)	Administration & General (000's) (h)	Allowance for Funds Used (000's) (i)	Taxes & Other (000's) (j)	Total Direct Charged Overheads (000's) (k)	
0					**0**	**1**
0	0	0	0	0	**0**	**2**
(8)		0	0	0	**(8)**	**3**
54	0	0	0	0	**54**	**4**
417	1	1	0	2	**421**	**5**
0	0	0	0	0	**0**	**6**
59	0	0	0	9	**68**	**7**
0	0	0	0	0	**0**	**8**
1,302	132	3	29	100	**1,566**	**9**
0		0	0	0	**0**	**10**
2,338	70	7	35	36	**2,486**	**11**
3,481	119	10	36	59	**3,705**	**12**
0	0	0	0	0	**0**	**13**
858	30	3	27	11	**929**	**14**
0	0	0	0	0	**0**	**15**
26,626	4,403	72	(149)	2,294	**33,246**	**16**
35,127	**4,755**	**96**	**(22)**	**2,511**	**42,467**	
	13.54%	**0.27%**	**-0.06%**	**7.15%**		
4,789	1,071	11	(148)	355	**6,078**	**17**
4,789	**1,071**	**11**	**(148)**	**355**	**6,078**	
	22.36%	**0.23%**	**-3.09%**	**7.41%**		
0					**0**	**18**
0	**0**	**0**	**0**	**0**	**0**	
0					**0**	**19**
0	**0**	**0**	**0**	**0**	**0**	
0					**0**	**20**
216	0	0	33	7	**256**	**21**
190	0	0	4	0	**194**	**22**
841	0	0	41	19	**901**	**23**
0	0	0	0	0	**0**	**24**
4,964	0	6	66	48	**5,084**	**25**
6,211	**0**	**6**	**144**	**74**	**6,435**	
	0.00%	**0.10%**	**2.32%**	**1.19%**		

CONSTRUCTION ACTIVITY FOR YEAR

Report below the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (000's) (b)	Company Materials (000's) (c)	Contractor Payments (000's) (d)	Other (000's) (e)	
Other					
NONE					**26**
Subtotal Other:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Grand Totals:	**8,780**	**19,570**	**16,296**	**1,481**	
% of Total Direct Charges:					

CONSTRUCTION ACTIVITY FOR YEAR (cont.)

	Overheads					
Total Direct Charges (000's) (f)	**Engineering & Supervision (000's) (g)**	**Administration & General (000's) (h)**	**Allowance for Funds Used (000's) (i)**	**Taxes & Other (000's) (j)**	**Total Direct Charged Overheads (000's) (k)**	
0					**0**	**26**
0	**0**	**0**	**0**	**0**	**0**	
46,127	**5,826**	**113**	**(26)**	**2,940**	**54,980**	
	12.63%	**0.24%**	**-0.06%**	**6.37%**		

CONSTRUCTION COMPLETED DURING YEAR

Report below the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (000's) (b)	Company Materials (000's) (c)	Contractor Payments (000's) (d)	Other (000's) (e)	
Electric					
Projects over $1,000,000					1
Electric Production	0	0	0	0	2
Bay Front #1 Asbestos Removal	3	5	409	0	3
Bay Front #2 Asbestos Removal		0	0	0	4
French Island Steam 1 & 2 Baghouse	0	0	0	54	5
French Island Units 1 & 2 Baghouse	0	0	(9)	0	6
St Croix Falls Hydro - Automation	21	9	23	5	7
Electric Transmission	0	0	0	0	8
T-Corners Substation Replace Transformer	339	854	204	74	9
T-Corners Susbstation - Install Cap Banks	0	0	0	0	10
					11
Projects under $1,000,000	6,776	13,774	6,742	2,531	12
Subtotal Electric:	**7,139**	**14,642**	**7,369**	**2,664**	
% of Subtotal Direct Charges:					
Gas					
Projects under $1,000,000	1,095	1,538	1,669	944	13
Subtotal Gas:	**1,095**	**1,538**	**1,669**	**944**	
% of Subtotal Direct Charges:					
Water					
NONE					14
Subtotal Water:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Steam					
NONE					15
Subtotal Steam:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Common					
Projects over $1,000,000	0	0	0	0	16
OMS One Outage Mgmt System	72	0	1,291	21	17
SS Western Ave Warehouse Expansion	93	5	1,800	0	18
CRS Customer Resource Systm P3 WI	293	3	7,966	(1,069)	19
	0	0	0	0	20
Projects under $1,000,000	263	1,141	5,781	61	21
Subtotal Common:	**721**	**1,149**	**16,838**	**(987)**	
% of Subtotal Direct Charges:					

CONSTRUCTION COMPLETED DURING YEAR (cont.)

Total Direct Charges (000's) (f)	Overheads: Engineering & Supervision (000's) (g)	Administration & General (000's) (h)	Allowance for Funds Used (000's) (i)	Taxes & Other (000's) (j)	Total Direct Charged Overheads (000's) (k)	
0					**0**	**1**
0	0	0	0	0	**0**	**2**
417	1	1	0	2	**421**	**3**
0	0	0	0	0	**0**	**4**
54	0	0	0	0	**54**	**5**
(9)	0	0	0	0	**(9)**	**6**
58	0	0	0	9	**67**	**7**
0	0	0	0	0	**0**	**8**
1,471	201	4	31	106	**1,813**	**9**
0	0	0	0	0	**0**	**10**
0					**0**	**11**
29,823	4,534	69	(46)	2,405	**36,785**	**12**
31,814	**4,736**	**74**	**(15)**	**2,522**	**39,131**	
	14.89%	**0.23%**	**-0.05%**	**7.93%**		
5,246	1,246	11	(136)	201	**6,568**	**13**
5,246	**1,246**	**11**	**(136)**	**201**	**6,568**	
	23.75%	**0.21%**	**-2.59%**	**3.83%**		
0					**0**	**14**
0	**0**	**0**	**0**	**0**	**0**	
0					**0**	**15**
0	**0**	**0**	**0**	**0**	**0**	
0	0	0	0	0	**0**	**16**
1,384	0	0	6	16	**1,406**	**17**
1,898	0	4	58	18	**1,978**	**18**
7,193	0	0	828	106	**8,127**	**19**
0	0	0	0	0	**0**	**20**
7,246	1	8	153	67	**7,475**	**21**
17,721	**1**	**12**	**1,045**	**207**	**18,986**	
	0.01%	**0.07%**	**5.90%**	**1.17%**		

CONSTRUCTION COMPLETED DURING YEAR

Report below the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

	Direct Charges				
Project Description (a)	Company Labor (000's) (b)	Company Materials (000's) (c)	Contractor Payments (000's) (d)	Other (000's) (e)	
Other					
NONE					22
Subtotal Other:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Grand Totals:	**8,955**	**17,329**	**25,876**	**2,621**	
% of Total Direct Charges:					

CONSTRUCTION COMPLETED DURING YEAR (cont.)

	Overheads					
Total Direct Charges (000's) (f)	Engineering & Supervision (000's) (g)	Administration & General (000's) (h)	Allowance for Funds Used (000's) (i)	Taxes & Other (000's) (j)	Total Direct Charged Overheads (000's) (k)	
0					0	22
0	0	0	0	0	0	
54,781	5,983	97	894	2,930	64,685	
	10.92%	0.18%	1.63%	5.35%		

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.)

1. Report with separate descriptions for each amount, the securities owned by the utility; include date of issue and date of maturity in description of any debt securities owned.
2. Designate any securities pledged and explain purpose of pledge in footnote.
3. Invesments less than $1,000 may be grouped by classes.
4. Report separately each fund account showing nature of assets included therein and list any securities included in fund accounts.

Description (a)	Date Acquired (b)	Maturity Date (c)		
Acct. 123 - Investment in Associated Companies				
NONE				1
Acct. 123.1 - Investment in Subsidiary Companies				
Chippewa and Flambeau Improvement Company - Capital Stock			*	2
Equity in undistributed earnings				3
Clearwater Investments, Inc. - Capital Stock	6/1/1992			4
Equity in undistributed earnings				5
NSP Lands, Inc. - Capital Stock	6/1/1992			6
Equity in undistributed earnings				7
Acct. 124 - Other Investments				
Economic Development Loans			*	8
Life Insurance Investments			*	9
Acct. 125 - Sinking Funds				
Red Cedar River Enhancement Fund			*	10
Acct. 126 - Depreciation Fund				
				11
Acct. 127 - Amortization Fund - Federal				
				12
Acct. 128 - Other Special Funds				
				13

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.) (cont.)

	Amount of Investment at Beginning Of Year (000's) (d)	Equity in Subsidiary Earnings Of Year (000's) (e)	Revenues For Year (000's) (f)	Amount of Investment at End Of Year (000's) (g)	Gain or Loss From Investment Disposed Of (000's) (h)		
Acct. 123 - Investment in Associated Companies							
				0			1
Acct. 123 Subtotal:	**0**	**0**	**0**	**0**	**0**		
Acct. 123.1 - Investment in Subsidiary Companies							
	549			**549**		*	2
	147	39	(38)	**148**	0		3
	150	0	0	**150**	0		4
	2,312	(89)	0	**2,223**	0		5
	50	0	0	**50**	0		6
	376	(9)	0	**367**	0		7
Acct. 123.1 Subtotal:	**3,584**	**(59)**	**(38)**	**3,487**	**0**		
Acct. 124 - Other Investments							
	5,470		(500)	**4,970**		*	8
	847		136	**983**	0	*	9
Acct. 124 Subtotal:	**6,317**	**0**	**(364)**	**5,953**	**0**		
Acct. 125 - Sinking Funds							
	0		135	**135**		*	10
Acct. 125 Subtotal:	**0**	**0**	**135**	**135**	**0**		
Acct. 126 - Depreciation Fund							
				0			11
Acct. 126 Subtotal:	**0**	**0**	**0**	**0**	**0**		
Acct. 127 - Amortization Fund - Federal							
				0			12
Acct. 127 Subtotal:	**0**	**0**	**0**	**0**	**0**		
Acct. 128 - Other Special Funds							
				0			13
Acct. 128 Subtotal:	**0**	**0**	**0**	**0**	**0**		
Total:	**9,901**	**(59)**	**(267)**	**9,575**	**0**		

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.)

Investments and Funds (Accts. 123-128, incl.) (Page F-19)

General footnotes

2. Capital stock for Chippewa and Flambeau Improvement Company was acquired through various purchases and stock dividends between September 20, 1926 and August 10, 1992.

8. $500,000 principal repaid on Economic Development loans during 2005.

9. Represents increase in the value of Northern States Power Company (Wisconsin)'s life insurance investments during 2005.

10. As part of the settlement agreement related to the relicensing of Northern States Power Company (Wisconsin)'s hydo projects on the Red Cedar River, Northern States Power Company (Wisconsin) established the Red Cedar River Enhancement Fund. The Red Cedar River Enhancement Fund will be used in the Lower Red Cedar River Basin to fund environmental protection, mitigation, restoration or educational activities and studies, fish protection measures, and other environmental measures deemed appropriate.

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.) (cont.)

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ACCOUNTS RECEIVABLE (ACCTS. 142-143)

Particulars (a)	Amount End of Year (000's) (b)	
Customer Accounts Receivable (142)		
Electric department	41,617	**1**
Gas department	19,543	**2**
Water department		**3**
Steam department		**4**
Other		**5**
Total Utility Service:	**61,160**	
Merchandising, jobbing and contract work		**6**
Other		**7**
Total (Acct. 142):	**61,160**	
Other Accounts Receivable (143)		
Officers and employees	50	**8**
Subscriptions to capital stock		**9**
All other (list separately items in excess of $250,000; group remaining items as Miscellaneous):		
Wisconsin Department of Transportation highway relocates	809	**10**
Opportunity Sales of Natural Gas	686	**11**
Damage Claims and Billing Jobs	291	**12**
Miscellaneous	119	**13**
Total (Acct. 143):	**1,955**	

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR (ACCT. 144)

Particulars (a)	Electric Utility Customers (000's) (b)	Gas Utility Customers (000's) (c)	Water Utility Customers (000's) (d)	Steam Utility Customers (000's) (e)	Other Utility Customers (000's) (f)	
Balance First of Year	1,364	(128)				1
Add: provision for uncollectibles during year						
Provision for uncollectibles during year	1,141	322				2
Collection of accts prev written off: Utility Customers	895	281				3
Other credits (explain in footnotes)						4
Total Credits:	**2,036**	**603**	**0**	**0**	**0**	
Less: Accounts written off						
Accounts written off during the year: Utility Customers	1,991	676				5
Other debits (explain in footnotes)						6
Total Debits:	**1,991**	**676**	**0**	**0**	**0**	
Balance End of Year:	**1,409**	**(201)**	**0**	**0**	**0**	

Particulars (a)	Total Utility Customers (000's) (g)	Officers & Employees (000's) (h)	Other (000's) (i)	Total (000's) (j)	
Balance First of Year	**1,236**		22	1,258	1
Add: provision for uncollectibles during year					
Provision for uncollectibles during year	**1,463**		387	1,850	2
Collection of accts prev written off: Utility Customers	**1,176**		66	1,242	3
Other credits (explain in footnotes)	**0**			0	4
Total Credits:	**2,639**	**0**	**453**	**3,092**	
Less: Accounts written off					
Accounts written off during the year: Utility Customers	**2,667**		222	2,889	5
Other debits (explain in footnotes)	**0**			0	6
Total Debits:	**2,667**	**0**	**222**	**2,889**	
Balance End of Year:	**1,208**	**0**	**253**	**1,461**	
Loss on Wisconsin utility accounts					
Accounts written off	**0**			2,581	7
Collection of such accounts	**0**			1,138	8
Net Loss:				**1,443**	

NOTES RECEIVABLE FROM ASSOCIATED COMPANIES (ACCT. 145)

Name of Company (a)	Issue Date (b)	Maturity Date (c)	Interest Rate (d)	Amount End of Year (000's) (e)	
NONE					1
			Total:	0	

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates for amounts by function are acceptable. In column (d), designate the departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating systems, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Account (a)	Balance First of Year (000's) (b)	Balance End of Year (000's) (c)	Department or Departments which Use Material (d)	
Fuel Stock (Account 151)	6,317	8,619	Electric	1
Fuel Stock Expenses Undistributed (Account 152)				2
Residuals and Extracted Products (Account 153)				3
Plant Materials and Operating Supplies (Account 154)				4
Assigned to Construction (Estimated)	2,217	2,337	Electric & Gas	5
Assigned to Operations and Maintenance				6
Production Plant (Estimated)	570	811	Electric	7
Transmission Plant (Estimated)	465	393	Electric	8
Distribution Plant (Estimated)	1,479	1,450	Electric & Gas	9
Assigned to - Other (provide details in footnote)	(41)	(18)		10
Total Account 154:	**4,690**	**4,973**		
Merchandise (Account 155)	19	3	Electric	11
Other Materials and Supplies (Account 156)				12
Nuclear Materials Held for Sale (Account 157)				13
Stores Expense Undistributed (Account 163)	0	0		14
Total Materials and Supplies:	**11,026**	**13,595**		

MATERIALS AND SUPPLIES

Materials and Supplies (Page F-24)

General footnotes

Explain any non-zero amounts under "Assigned to - Other" line 10

Column B	(48)	obsolescence
	7	misc. inventory related items
Total	(41)	
Column C	(33)	obsolescence
	15	purchase price variances
Total	(18)	

UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (ACCTS. 181, 225, 226 AND 257)

1. Report below the particulars called for with respect to the unamortized debt discount and expense or net premium applicable to each class and series of long-term debt. Show separately any unamortized debt discount and expense or call premiums applicable to refunded issues. Show in column (a) the series, due date and method of amortization for each amount of debt discount and expense or premium. In column (b) show principal amount of debt on which the total discount and expense or premium, shown in column (c), was incurred.
2. Explain any charges or credits in column (f) and (g) other than amortization in Acct. 428 or 429.

Debt to Which Related (a)	Prin. Amt. of Debt to which Disc. and Exp. or Net Premiums Relate (000's) (b)	Total Discount and Expense or (net premiums) (000's) (c)	
Unamortized Debt Discount and Expense (181)			
First Mortgage Bonds Series Due Dec 01, 2026	65,000	493	**1**
First Mortgage Bonds Series Due Oct 01, 2018	150,000	1,423	**2**
Resource Recovery Financing Due Nov 01, 2021	18,600	193	**3**
Senior Notes Series Due Oct 01, 2008	80,000	608	**4**
Total (Acct. 181):	**313,600**	**2,717**	
Umamortized Premium on Long-Term Debt (225)			
NONE			**5**
Total (Acct. 225):	**0**	**0**	
Umamortized Discount on Long-Term Debt - Debit (22			
First Mortgage Bonds Series Due Dec 01, 2026	65,000	268	**6**
First Mortgage Bonds Series Due Oct 01, 2018	150,000	861	**7**
Total (Acct. 226):	**215,000**	**1,129**	
Umamortized Gain on Reacquired Debt (257)			
NONE			**8**
Total (Acct. 257):	**0**	**0**	

UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (ACCTS. 181, 225, 226 AND 257) (cont.)

Balance First of Year (000's) (d)	Account Charged or Credited (e)	Charges During Year (000's) (f)	Credits During Year (000's) (g)	Balance End of Year (000's) (h)	
360	428		16	**344**	**1**
1,303	428	0	95	**1,208**	**2**
92	428	0	6	**86**	**3**
281	146 / 428	7	76	**212**	**4**
2,036		**7**	**193**	**1,850**	
				0	**5**
0		**0**	**0**	**0**	
196	428		9	**187**	**6**
789	428	0	57	**732**	**7**
985		**0**	**66**	**919**	
				0	**8**
0		**0**	**0**	**0**	

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making process of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show the period of amortization in column (a).
3. Minor items (5% of the Balance End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Description and Purpose of Other Regulatory Assets (a)	Balance First of Year (000's) (b)	Debit Amount (000's) (c)	Credits Account Charged (d)	Credits Amount (000's) (e)	Balance End of Year (000's) (f)		
AFC in Excess of FERC-Carrying Chgs-Electric -Amortized over plant lives	2,247	337	405	114	**2,470**		**1**
AFC in Excess of FERC-Carrying Chgs-Gas -Amortized over plant lives	459	0	Various	40	**419**	*	**2**
AFC in Excess of FERC-Carrying Chgs-Common -Amortized over plant lives	533	346	405	84	**795**		**3**
Net-of-Tax AFUDC Adjustments - SFAS 109 -Amortized over plant lives	8,226	0	282	173	**8,053**		**4**
Conservation Programs -Amortization amount per PSCW rate order 4220-UR-113	53	6,672	908	6,516	**209**		**5**
Pension Transition Liability -Amortized over 15 years beginning 1993	268	0	184	90	**178**		**6**
Environmental Cleanup - MGP Sites -Amortization amount per PSCW rate order 4220-UR-113	24,970	7,002	735	1,017	**30,955**		**7**
Michigan Restructuring	30	0		0	**30**		**8**
Wisconsin Public Benefits - Amortization amount per PSCW rate order 4220-UR-113	277	0	905	238	**39**		**9**
Retail Gas Costs - SFAS 133	1,060	0	219	1,060	**0**		**10**
Deferred Electric Fuel Cost - Michigan PSCR -Amortized over 12 month period	0	903		0	**903**		**11**
MISO Day 2 WI Retail Deferral	0	5,732		0	**5,732**		**12**
Total:	**38,123**	**20,992**		**9,332**	**49,783**		

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

Other Regulatory Assets (Account 182.3) (Page F-27)

General footnotes

2. Accounts Charged for Credits:

421	2
405	38
Total	40

MISCELLANEOUS DEFERRED DEBITS (ACCT. 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show the period of amortization in column (a).
3. Minor items (5% of the Balance End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Description (a)	Balance First of Year (000's) (b)	Debit Amount (000's) (c)	Credits: Account Charged (d)	Credits: Amount (000's) (e)	Balance End of Year (000's) (f)	
Misc Debits Under $50,000	22	5		0	**27**	**1**
Pension Accrued - SFAS 87	52,272	2,495		0	**54,767**	**2**
Contracts Receivable	4,512	1,805	Various	2,027	**4,290**	**3**
Notes Receivable CIP Loans	0	33		0	**33**	**4**
Total:	**56,806**	**4,338**		**2,027**	**59,117**	

RESEARCH AND DEVELOPMENT EXPENDITURES (ACCT. 188)

1. Explain below and show the cost incurred during the year for technological research and development projects including amounts paid to others during the year for jointly sponsored projects and other payments made as a result of the company's membership in trade or technical associationsand subscriptions or assessments for such projects.
2. Items under $5,000 incurred for similar projects may be grouped.
3. For any R&D work carried on by the company in which there is a sharing of costs with others, show separately the company's cost for the year and cost chargeable to others.

Description (a)	Balance First of Year (000's) (b)	Debit Amount (000's) (c)	Credits: Account Charged (d)	Credits: Amount (000's) (e)	Balance End of Year (000's) (f)	
Electric Power Research Institute:	0	0		0	**0**	**1**
Fees		49	930.2	49	**0**	**2**
Hydrogen Program Membership	0	1	930.2	1	**0**	**3**
Edison Electric Institute:	0	0		0	**0**	**4**
Dues	0	74	930.2	74	**0**	**5**
Other	0	1	923	1	**0**	**6**
National Renewable Energy Labortory	0	1	923	1	**0**	**7**
	0				**0**	**8**
Total:	**0**	**126**		**126**	**0**	

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, explain in footnote giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Class and Series of Stock (a)	Balance End of Year (000's) (b)	
NONE		1
Total:	**0**	

ACCUMULATED DEFERRED INCOME TAXES (ACCT. 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify in Footnote), include deferrals relating to other income and deductions.

Description and Location (a)	Balance First of Year (000's) (b)	Balance End of Year (000's) (c)	
Electric			
Electric	32,955	34,329	1
Other	0	0	2
Total Electric:	**32,955**	**34,329**	
Water			
NONE			3
Total Water:	**0**	**0**	
Other (Specify in footnote)			
Gas	9,955	11,208	4
Total Other (Specify in footnote):	**9,955**	**11,208**	
Common			
NONE			5
Total Common:	**0**	**0**	
Non-Utility			
Non Operating	509	191	6
Total Non-Utility:	**509**	**191**	
Total Account 190:	**43,419**	**45,728**	

ACCUMULATED DEFERRED INCOME TAXES (ACCT. 190)

Accumulated Deferred Income Taxes (Acct. 190) (Page F-31)

General footnotes

	12/31/2004	12/31/2005
Electric (Other)		
Avoided Tax Interest	5,320,570	5,522,702
Bad Debts	555,912	548,089
Contributions In Aid Const-Connection Fees	7,057,762	8,407,855
Customer Adv - Construction	5,518,467	5,305,404
Deferred Compensation Plan Reserve	996,399	944,608
ESOP Dividends	325,529	415,517
Executive Incentive Plans	70,116	151,138
FAS 109- Effect of Rate Changes	1,310,522	1,482,353
FAS 109- ITC Grossup	8,603,577	8,122,036
Fuel Tax Credit - Inc Addback FED Only	0	2,140
Inventory Reserve	17,479	11,860
Litigation Reserve	584,977	341,193
Medical Deductions - Self Insured	102,265	134,784
Post Employment Benefits - FAS 106	1,559,397	2,169,668
Post Employment Benefits - FAS 112	118,923	243,539
Regulatory Liability - IRC Sec 199	0	66,617
Regulatory Reserve	159,002	(362,361)
Sale of Emission Allowances	54,040	97,947
Severance Accrual	12,990	0
Vacation Accrual	586,975	724,329
Total	32,954,902	34,329,418

	12/31/2004	12/31/2005
Gas (Other)		
Avoided Tax Interest	375,565	339,104
Bad Debts	(51,250)	38,512
Contributions In Aid Const-Connection Fees	1,514,115	1,064,662
Customer Adv - Construction	88,783	506,306
Deferred Compensation Plan Reserve	183,329	162,657
Environmental Remediation	7,204,935	8,133,823
ESOP Dividends	101,243	133,704
Executive Incentive Plans	12,900	26,026
FAS 109- Effect of Rate Changes	(18,120)	45,417
FAS 109- ITC Grossup	262,873	227,073
Inventory Reserve	2,033	1,362
Lower of Cost or Mkt on Gas Invent	26,932	31,218
Medical Deductions - Self Insured	18,816	23,209
Post Employment Benefits - FAS 106	286,917	373,608
Post Employment Benefits - FAS 112	21,881	41,936
Severance Accrual	2,390	0
Unbilled Revenue	(186,248)	(65,860)
Vacation Accrual	107,999	124,727
Total	9,955,093	11,207,484

	12/31/2004	12/31/2005
Nonutility		
Amortization - Start-Up Costs	43,850	0
Contributions Carryover	464,946	190,721
Total	508,796	190,721

ACCUMULATED DEFERRED INCOME TAXES (ACCT. 190)

CAPITAL STOCKS (ACCTS. 201 AND 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (000's) (d)	
Common Stock				
Common Stock	1,000,000	0.00	0	**1**
All NSP-Wisconsin Common Stock is owned by	0	0.00	0	**2**
its parent, Xcel Energy Inc.	0	0.00	0	**3**
		0.00	0	**4**
Total Common:	**1,000,000**			

CAPITAL STOCKS (ACCTS. 201 AND 204) (cont.)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year. Give particulars (detais) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

Outstanding per Balance Sheet (Total amount outstanding without reduction for amounts held by respondent)		Held by Respondent: As Reacquired Stock (Account 217)		Held by Respondent: In Sinking and Other Funds		
Shares (e)	Amount (000's) (f)	Shares (g)	Cost (000's) (h)	Shares (i)	Amount (000's) (j)	
933,000	93,300	0	0	0	0	**1**
0	0	0	0	0	0	**2**
0	0	0	0	0	0	**3**
		0	0	0	0	**4**
933,000	**93,300**	**0**	**0**	**0**	**0**	

OTHER PAID-IN CAPITAL (ACCTS. 206-211, INCL.)

Report below the balance at the end of the year and the information specified below for the respective Other Paid-In-Capital accounts. Provide a subheading for each account and show a total for the account, as well as total for all accounts for reconciliation with Balance Sheet. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208): State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211): Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Item (a)	Amount (000's) (b)	
Account 211 - Miscellaneous Paid in Capital	0	**1**
Acquisition of Natural Gas, Inc. common stock (1998)	80	**2**
Contribution of capital by parent company (2001)	26,354	**3**
Contribution of capital by parent company (2002)	3,210	**4**
Contribution of capital by parent company (2003)	476	**5**
Contribution of capital by parent company (2004)	1,820	**6**
Contribution of capital by parent company (2005)	22,530	**7**
TOTAL	54,469	**8**

LONG-TERM DEBT (ACCTS. 221-224, INCL.)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221 (Bonds), 222 (Reacquired Bonds), 223 (Advances from Associated Companies), and 224 (Other Long-Term Debt).
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column(a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show the interest or dividend rate of the debt issued.
7. In column (c) show the principal amount of bonds or other long-term debt originally issued.
8. In column (d) show the expense amount with respect to the amount of bonds or other long-term debt originally issued.
9. In column (e) show the premium amount with respect to the amount of bonds or other long-term debt originally issued.
10. In column (f) show the discount amount with respect to the amount of bonds or other long-term debt originally issued.
11. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Class and Series of Obligation, Coupon Rate (For new issue, give commission authorization numbers and dates) (a)	Interest or Dividend Rate (b)	Principal Amount of Debt Issued (000's) (c)	
Account 221			
Series: NONE			
First Mortgage Bonds	5.250000%	150,000	**1**
First Mortgage Bonds	7.375000%	65,000	**2**
Subtotal NONE:		**215,000**	
Subtotal Account 221:		**215,000**	
Account 222			
Series: NONE			
NONE			**3**
Subtotal NONE:		**0**	
Subtotal Account 222:		**0**	
Account 223			
Series: NONE			
NONE			**4**
Subtotal NONE:		**0**	
Subtotal Account 223:		**0**	
Account 224			
Series: NONE			
Resource Recovery Revenue Bonds	6.000000%	18,600	**5**
Fort McCoy System Acquisition	7.000000%	997	**6**
Senior Notes	7.640000%	80,000	**7**
Subtotal NONE:		**99,597**	
Subtotal Account 224:		**99,597**	
Total:		**314,597**	

LONG-TERM DEBT (ACCTS. 221-224, INCL.) (cont.)

12. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
13. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
14. In a footnote, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during the year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
15. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
16. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
17. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (j). Explain in a footnote any difference between the total of column (j) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
18. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Total Expense Amount (000's) (d)	Total Premium Amount (000's) (e)	Total Discount Amount (000's) (f)	Nominal Date of Issue (g)	Date of Maturity (h)	Outstanding Amount (000's) (i)	Interest for Year Amount (000's) (j)	
1,423	0	861	10/02/2003	10/01/2018	150,000	8,002	1
493	0	268	12/12/1996	12/01/2026	65,000	4,794	2
1,916	**0**	**1,129**			**215,000**	**12,796**	
1,916	**0**	**1,129**			**215,000**	**12,796**	
							3
0	**0**	**0**			**0**	**0**	
0	**0**	**0**			**0**	**0**	
							4
0	**0**	**0**			**0**	**0**	
0	**0**	**0**			**0**	**0**	
193		0	11/01/1996	11/01/2021	18,600	1,116	5
	0	0	10/15/2000	10/15/2030	828	60	6
608			09/25/2000	10/01/2008	80,000	6,112	7
801	**0**	**0**			**99,428**	**7,288**	
801	**0**	**0**			**99,428**	**7,288**	
2,717	**0**	**1,129**			**314,428**	**20,084**	

STATEMENT OF RETAINED EARNINGS

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or apropriated as well as the totals eventually to be accumulated.

Item (a)	Contra Primary Account Affected (b)	Amount (000's) (c)	
UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
Balance Beginning of Year		260,763	**1**
Changes			**2**
Adjustments to Retained Earnings (Account 439)			**3**
		(1)	**4**
		0	**5**
		0	**6**
		0	**7**
		0	**8**
TOTAL Credits to Retained Earnings (Acct. 439)		**(1)**	**9**
		0	**10**
		0	**11**
		0	**12**
		0	**13**
		0	**14**
TOTAL Debits to Retained Earnings (Acct. 439)		**0**	**15**
Balance Transferred from Income (Account 433 less Account 418.1)		26,632	**16**
Appropriations of Retained Earnings (Acct. 436)			**17**
Amortization Reserve - Federal		0	**18**
		0	**19**
		0	**20**
		0	**21**
TOTAL Appropriations of Retained Earnings (Acct. 436)		**0**	**22**
Dividends Declared-Preferred Stock (Account 437)			**23**
		0	**24**
		0	**25**
		0	**26**
		0	**27**
		0	**28**
TOTAL Dividends Declared-Preferred Stock (Account 437)		**0**	**29**
Dividends Declared-Common Stock (Account 438)			**30**
Dividends Declared-Common Stock (Account 438)		(44,318)	**31**
		0	**32**
		0	**33**
		0	**34**
		0	**35**
TOTAL Dividends Declared-Common Stock (Account 438)		**(44,318)**	**36**

STATEMENT OF RETAINED EARNINGS

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or apropriated as well as the totals eventually to be accumulated.

Item (a)	Contra Primary Account Affected (b)	Amount (000's) (c)	
Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		38	**37**
Balance - End of Year (Total 1, 9, 15, 16, 22, 29, 36, 37)		**243,114**	**38**
APPROPRIATED RETAINED EARNINGS (Account 215)			
		0	**39**
		0	**40**
		0	**41**
		0	**42**
		0	**43**
		0	**44**
TOTAL Appropriated Retained Earnings (Account 215)		**0**	**45**
APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		11,494	**46**
TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45, 46)		**11,494**	**47**
TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47)		**254,608**	**48**
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
Balance-Beginning of Year (Debit or Credit)		2,835	**49**
Equity in Earnings for Year (Credit) (Account 418.1)		(59)	**50**
Less: Dividends Received (Debit)		38	**51**
		0	**52**
Balance-End of Year (Total lines 49 thru 52)		**2,738**	**53**

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges," report the accounts affected and the related amounts in a footnote.

Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (000's) (b)	Minimum Pension Liability Adjustment (net amount) (000's) (c)	Foreign Currency Hedges (000's) (d)	
Balance of Account 219 at Beginning of Preceding Year	0	0	0	1
Preceding Year Reclassification from Account 219 to Net income	0	0	0	2
Preceding Year Changes in Fair Value	0	0	0	3
Total (lines 2 and 3)	0	0	0	4
Balance of Account 219 at End of Preceding Year	0	0	0	5
Current Year Reclassifications from Account 219 to Net Income	0	0	0	6
Current Year Changes in Fair Value	0	0	0	7
Total (lines 6 and 7)				8
Balance of Account 219 at End of Current Year	0	0	0	9

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES (cont.)

Other Adjustments (000's) (e)	Other Cash Flow Hedges (Financial Swaps for Gas) (000's) (f)	Other Cash Flow Hedges (Specify in Footnote) (000's) (g)	Totals for each category of items recorded in Account 219 (000's) (h)	Net Income (000's) (i)	Total Comprehensive Income (000's) (j)	
0	0	(1,122)	(1,122)			1
0	0	76	76			2
0	0	0	0			3
0	0	76	76	54,385	54,461	4
0	0	(1,046)	(1,046)			5
0	0	77	77			6
0	0	0	0			7
		77	77	26,573	26,650	8
0	0	(969)	(969)			9

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Statements of Accumulated Comprehensive Income, Comprehensive Income, and Hedging Activities (Page F-38)

General footnotes

Amounts in column (g) relate to SFAS 133 activity.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES (cont.)

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NOTES PAYABLE (ACCT. 231)

1. Report each issue separately.
2. If there is more than one interest rate for an aggregate obligation issue, average the interest rates and report one rate.

Name of Payee and Purpose for which Issued (a)	Date of Note (b)	Date of Maturity (c)	Interest Rate (d)	Balance End of Year (000's) (e)	
NONE					1

NOTES PAYABLE TO ASSOCIATED COMPANIES (ACCT. 233)

Name of Company (a)	Issue Date (b)	Maturity Date (c)	Interest Rate (d)	Amount End of Year (000's) (e)	
NSP-MN Intercompany borrowing agreement	01/01/2005		0.000%	64,000	* 1
			Total:	**64,000**	

NOTES PAYABLE TO ASSOCIATED COMPANIES (ACCT. 233)

Notes Payable to Associated Companies (Acct. 233) (Page F-41)

General footnotes

NSP-Wisconsin has an intercompany borrowing arrangement with NSP-Minnesota, with interest charged at NSP-Minnesota's short-term borrowing rate, which is variable.

TAXES ACCRUED (ACCT. 236)

1. The balance of accruals for income taxes should be classified by the years to which the tax is applicable.
2. The balance of any accruals materially in excess of the liability admitted by the tax returns of the utility shall be transferred from this account and reported in an appropriately designated reserve account.

Kind of Tax (a)	Balance First of Year (000's) (b)	Amounts Accrued (000's) (c)	Payments During Year (000's) (d)	Other Items cr. or (dr.) (000's) (e)	Balance End of Year (000's) (f)		
FEDERAL Income	594	10,352	8,043	467	**3,370**	*	1
Unemployment-2004	1	0	1	0	**0**		2
Unemployment-2005	0	36	34	(1)	**1**	*	3
FICA-2004	41	0	41	0	**0**		4
FICA-2005	0	3,010	2,915	(63)	**32**	*	5
	0	0	0	0	**0**		6
WISCONSIN Income	(153)	2,470	2,878	561	**0**	*	7
Unemployment-2004	1	0	1	0	**0**		8
Unemployment-2005	0	82	89	8	**1**		9
Real-Estate-2004	129	0	129	0	**0**		10
Real-Estate-2005	0	112	5	31	**138**	*	11
Use-2004	20	0	20	0	**0**		12
Use-2005	0	855	766	0	**89**		13
	0	0	0	0	**0**		14
MICHIGAN Income	(18)	117	83	0	**16**		15
Unemployment-2004	0	0	0	0	**0**		16
Unemployment-2005	0	13	3	(10)	**0**	*	17
Real-Estate-2004	37	0	37	0	**0**		18
Real-Estate-2005	0	115	84	0	**31**		19
Personal Property-2004	118	0	118	0	**0**		20
Personal Property-2005	0	454	353	2	**103**	*	21
Use-2004	0	0	0	0	**0**		22
Use-2005	0	3	2	0	**1**		23
	0	0	0	0	**0**		24
KANSAS Personal Property Tax-2004	131	119	0	0	**250**		25
	0	0	0	0	**0**		26
Xcel Services Misc. alloc.	0	16	16	0	**0**		27
	0	0	0	0	**0**		28
Total:	**901**	**17,754**	**15,618**	**995**	**4,032**		

TAXES ACCRUED (ACCT. 236)

Taxes Accrued (Acct. 236) (Page F-42)

General footnotes

Detail of other credit or debit items, column (e)

1	Interest on audits	469
	Payments from subsidiaries	(2)
	Total	467
3	Other	(1)
5	Other	(63)
7	Interest on audits	133
	Reclass debit accrual balance to FERC 165	428
	Total	561
11	Capitalized special assessments	31
17	Posting error correction	(10)
21	Prior year tax refund	2

OTHER DEFERRED CREDITS (ACCOUNT 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Description (a)	Balance First of Year (000's) (b)	Debits Contra Account (c)	Debits Amount (000's) (d)	Credit Amount (000's) (e)	Balance End of Year (000's) (f)	
Line Extension Projects	10	Various	10	0	**0**	**1**
Deferred Comp Liability	678	Various	43	0	**635**	**2**
Deferred Comp Wealth Option	687	Various	90	0	**597**	**3**
Environmental Cleanup Liability	15,007	242	1,047	3,591	**17,551**	**4**
SFAS 106 Benefits Liability	4,603	Various	2,821	3,363	**5,145**	**5**
Red Cedar River Enhancement Fund	0		0	135	**135**	**6**
Total:	**20,985**		**4,011**	**7,089**	**24,063**	

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (h) the average period over which tax credits are amortized.

Account Subdivisions (a)	Balance First of Year (000's) (b)	Deferred for Year Acct. No. (c)	Deferred for Year Amount (000's) (d)	Allocations to Current Year's Income Acct. No. (e)	Allocations to Current Year's Income Amount (000's) (f)		
Electric							
4%	47		0		12		1
10%	12,636		0		708		2
Total Electric:	**12,683**		**0**		**720**		
Gas							
3%							3
4%	5				2		4
7%							5
10%	365				50		6
Total Gas:	**370**		**0**		**52**		
Water							
3%							7
4%							8
7%							9
10%							10
Total Water:	**0**		**0**		**0**		
Common							
3%							11
4%							12
7%							13
10%	183				13	*	14
Total Common:	**183**		**0**		**13**		
Nonutility							
3%							15
4%							16
7%							17
10%	1					*	18
Total Nonutility:	**1**		**0**		**0**		
Other (Specify in Footnote)							
3%							19
4%							20
7%							21
10%							22
Total Other (Specify in Footnote):	**0**		**0**		**0**		
Total	**13,237**		**0**		**785**		

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255) (cont.)

Adjustments (000's) (g)	Balance End of Year (000's) (h)	Average Period of Allocation to Income (i)	Adjustment Explanation (j)		
0	**35**				**1**
0	**11,928**				**2**
0	**11,963**				
	0				**3**
	3				**4**
	0				**5**
	315				**6**
0	**318**				
	0				**7**
	0				**8**
	0				**9**
	0				**10**
0	**0**				
	0				**11**
	0				**12**
	0				**13**
	170			*	**14**
0	**170**				
	0				**15**
	0				**16**
	0				**17**
(1)	**0**			*	**18**
(1)	**0**				
	0				**19**
	0				**20**
	0				**21**
	0				**22**
0	**0**				
(1)	**12,451**				

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255)

Accumulated Deferred Investment Tax Credits (Acct. 255) (Page F-44)

General footnotes

14. Common Allocation

Electric - 88.63%	162
Gas - 11.37%	21
Total	183

18. The adjustment represents amortization of the non-utility tax benefits transer (safe harbor) lease credit which have no income effect.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255) (cont.)

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ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (ACCT. 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. For Other (Specify in Footnote), include deferrals relating to other income and deductions.

Particulars (a)	Balance First of Year (000's) (b)	Changes During Year: Amounts Debited to Acct. 410.1 (000's) (c)	Amounts Credited to Acct. 411.1 (000's) (d)	Amounts Debited to Acct. 410.2 (000's) (e)	Amounts Credited to Acct. 411.2 (000's) (f)	
Account 281						
Electric						
Pollution Control Facilities	48	(31)				1
Total Electric:	**48**	**(31)**	**0**	**0**	**0**	
Gas						
NONE						2
Total Gas:	**0**	**0**	**0**	**0**	**0**	
Water						
NONE						3
Total Water:	**0**	**0**	**0**	**0**	**0**	
Steam						
NONE						4
Total Steam:	**0**	**0**	**0**	**0**	**0**	
Common						
NONE						5
Total Common:	**0**	**0**	**0**	**0**	**0**	
Non-Utility						
NONE						6
Total Non-Utility:	**0**	**0**	**0**	**0**	**0**	
Other (Specify in Footnotes)						
NONE						7
Total Other (Specify in Footnotes):	**0**	**0**	**0**	**0**	**0**	
Total Account 281:	**48**	**(31)**	**0**	**0**	**0**	
Classification of Total						
Federal Income Tax	36	(23)				8
State Income Tax	12	(8)				9
Local Income Tax						10
Total:	**48**	**(31)**	**0**	**0**	**0**	

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (ACCT. 281) (cont.)

	Adjustments: Debits: Account Charged (g)	Adjustments: Debits: Amount (000's) (h)	Adjustments: Credits: Account Charged (i)	Adjustments: Credits: Amount (000's) (j)	Balance End of Year (000's) (k)	
					17	1
		0		0	17	
					0	2
		0		0	0	
					0	3
		0		0	0	
					0	4
		0		0	0	
					0	5
		0		0	0	
					0	6
		0		0	0	
					0	7
		0		0	0	
		0		0	17	
					13	8
					4	9
					0	10
		0		0	17	

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (ACCT. 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. For Other (Specify in Footnote), include deferrals relating to other income and deductions.

Particulars (a)	Balance First of Year (000's) (b)	Changes During Year: Amounts Debited to Acct. 410.1 (000's) (c)	Amounts Credited to Acct. 411.1 (000's) (d)	Amounts Debited to Acct. 410.2 (000's) (e)	Amounts Credited to Acct. 411.2 (000's) (f)	
Account 282						
Electric						
	155,992	(384)	0	0	0	1
Total Electric:	**155,992**	**(384)**	**0**	**0**	**0**	
Gas						
	9,277	558	0	0	0	2
Total Gas:	**9,277**	**558**	**0**	**0**	**0**	
Water						
NONE						3
Total Water:	**0**	**0**	**0**	**0**	**0**	
Steam						
NONE						4
Total Steam:	**0**	**0**	**0**	**0**	**0**	
Common						
NONE						5
Total Common:	**0**	**0**	**0**	**0**	**0**	
Non-Utility						
NONE						6
Total Non-Utility:	**0**	**0**	**0**	**0**	**0**	
Other (Specify in Footnote)						
Non-Operating	(19)			1		7
Total Other (Specify in Footnote):	**(19)**	**0**	**0**	**1**	**0**	
Total Account 282:	**165,250**	**174**	**0**	**1**	**0**	
Classification of Total						
Federal Income Tax	135,427	(183)	0	1	0	8
State Income Tax	29,823	357	0	0	0	9
Local Income Tax						10
Total:	**165,250**	**174**	**0**	**1**	**0**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (ACCT. 282) (cont.)

	Adjustments					
	Debits		Credits			
	Account Charged (g)	Amount (000's) (h)	Account Charged (i)	Amount (000's) (j)	Balance End of Year (000's) (k)	
	182.3 & 254	208	182.3 & 254	555	**155,955**	**1**
		208		**555**	**155,955**	
	182.3 & 254	95	182.3 & 254	43	**9,783**	**2**
		95		**43**	**9,783**	
					0	**3**
		0		**0**	**0**	
					0	**4**
		0		**0**	**0**	
					0	**5**
		0		**0**	**0**	
					0	**6**
		0		**0**	**0**	
					(18)	**7**
		0		**0**	**(18)**	
		303		**598**	**165,720**	
		221		412	**135,436**	**8**
		82		186	**30,284**	**9**
					0	**10**
		303		**598**	**165,720**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER (ACCT. 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For Other (Specify in Footnote), include deferrals relating to other income and deductions.

Particulars (a)	Balance First of Year (000's) (b)	Changes During Year: Amounts Debited to Acct. 410.1 (000's) (c)	Changes During Year: Amounts Credited to Acct. 411.1 (000's) (d)	Changes During Year: Amounts Debited to Acct. 410.2 (000's) (e)	Changes During Year: Amounts Credited to Acct. 411.2 (000's) (f)	
Account 283						
Electric						
Electric	29,671	25,102	22,035			1
Total Electric:	**29,671**	**25,102**	**22,035**	**0**	**0**	
Gas						
Gas	14,513	6,516	4,153			2
Total Gas:	**14,513**	**6,516**	**4,153**	**0**	**0**	
Water						
NONE						3
Total Water:	**0**	**0**	**0**	**0**	**0**	
Steam						
NONE						4
Total Steam:	**0**	**0**	**0**	**0**	**0**	
Common						
NONE						5
Total Common:	**0**	**0**	**0**	**0**	**0**	
Non-Utility						
NONE						6
Total Non-Utility:	**0**	**0**	**0**	**0**	**0**	
Other (Specify in Footnotes)						
Non-Operating	(694)				6	7
Total Other (Specify in Footnotes):	**(694)**	**0**	**0**	**0**	**6**	
Total Account 283:	**43,490**	**31,618**	**26,188**	**0**	**6**	
Classification of Total						
Federal Income Tax	34,959	25,436	21,028		6	8
State Income Tax	8,531	6,182	5,160			9
Local Income Tax						10
Total:	**43,490**	**31,618**	**26,188**	**0**	**6**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER (ACCT. 283) (cont.)

	Adjustments - Debits: Account Charged (g)	Adjustments - Debits: Amount (000's) (h)	Adjustments - Credits: Account Charged (i)	Adjustments - Credits: Amount (000's) (j)	Balance End of Year (000's) (k)	
					32,738	**1**
		0		**0**	**32,738**	
					16,876	**2**
		0		**0**	**16,876**	
					0	**3**
		0		**0**	**0**	
					0	**4**
		0		**0**	**0**	
					0	**5**
		0		**0**	**0**	
					0	**6**
		0		**0**	**0**	
			219.1 & 283	51	**(649)**	**7**
		0		**51**	**(649)**	
		0		**51**	**48,965**	
				41	**39,402**	**8**
				10	**9,563**	**9**
					0	**10**
		0		**51**	**48,965**	

BALANCE SHEET END-OF-YEAR ACCOUNT BALANCES

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (000's) (b)	
Cash (131):		
NONE		1
Total (Acct. 131):	**0**	
Interest Special Deposits (132):		
NONE		2
Total (Acct. 132):	**0**	
Dividend Special Deposits (133):		
NONE		3
Total (Acct. 133):	**0**	
Other Special Deposits (134):		
NONE		4
Total (Acct. 134):	**0**	
Working Funds (135):		
CASH AGENTS / EMPLOYEE WORKING FUNDS	100	5
Total (Acct. 135):	**100**	
Temporary Cash Investments (136):		
NONE		6
Total (Acct. 136):	**0**	
Notes Receivable (141):		
NONE		7
Total (Acct. 141):	**0**	
Accounts Receivable from Associated Companies (146):		
SOUTHWESTERN PUBLIC SERVICE COMPANY	337	8
XCEL ENERGY INC.	7,513	9
PUBLIC SERVICE COMPANY OF COLORADO	2,282	10
Total (Acct. 146):	**10,132**	
Fuel Stock (151):		
OIL INVENTORY	7,578	11
COAL INVENTORY	513	12
FUEL IN TRANSIT	425	13
MISCELLANEOUS	103	14
Total (Acct. 151):	**8,619**	
Fuel Stock Expenses Undistributed (152):		
NONE		15
Total (Acct. 152):	**0**	

BALANCE SHEET END-OF-YEAR ACCOUNT BALANCES

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (000's) (b)	
Residuals (153):		
NONE		16
Total (Acct. 153):	**0**	
Plant Materials and Operating Supplies (154):		
MATERIALS AND SUPPLIES USED IN CONSTRUCTION AND OPERATION	4,973	17
AND MAINTENANCE OF PLANT		18
Total (Acct. 154):	**4,973**	
Merchandise (155):		
MISCELLANEOUS	3	19
Total (Acct. 155):	**3**	
Other Materials and Supplies (156):		
NONE		20
Total (Acct. 156):	**0**	
Nuclear Materials Held for Sale (157):		
NONE		21
Total (Acct. 157):	**0**	
Allowances (Noncurrent Portion of Allowances) (158):		
NONE		22
Total (Acct. 158):	**0**	
Stores Expense Undistributed (163):		
NONE		23
Total (Acct. 163):	**0**	
Gas Stored Underground-Current (164.1):		
COMMODITY INJECTION FEES	123	24
COMMODITY COSTS TRANSFERED TO STORAGE	49,657	25
TRANSMISSION EXPENSE TRANSFERED TO STORAGE	1,386	26
STORED GAS WITHDRAWN FOR SYSTEM	(36,931)	27
Total (Acct. 164.1):	**14,235**	
LNG Stored (164.2):		
LNG STORED	263	28
Total (Acct. 164.2):	**263**	
Held for Processing (164.3):		
NONE		29
Total (Acct. 164.3):	**0**	
Prepayments (165):		
GROSS RECEIPTS TAX	14,033	30
INSURANCE	1,331	31

BALANCE SHEET END-OF-YEAR ACCOUNT BALANCES

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (000's) (b)	
Prepayments (165):		
VEBA TRUST	441	**32**
WISCONSIN INCOME TAX PREPAYMENT	428	**33**
GAS IMBALANCE	320	**34**
WISCONSIN REMAINDER ASSESSMENT	279	**35**
MISCELLANEOUS	28	**36**
Total (Acct. 165):	**16,860**	
Advances for Gas (166-167):		
NONE		**37**
Total (Acct. 166-167):	**0**	
Interest and Dividends Receivable (171):		
NONE		**38**
Total (Acct. 171):	**0**	
Rents Receivable (172):		
NONE		**39**
Total (Acct. 172):	**0**	
Accrued Utility Revenues (173):		
ELECTRIC RETAIL	19,754	**40**
ELECTRIC WHOLESALE	179	**41**
GAS	19,992	**42**
Total (Acct. 173):	**39,925**	
Miscellaneous Current and Accrued Assets (174):		
NONE		**43**
Total (Acct. 174):	**0**	
Capital Stock Expense (214):		
NONE		**44**
Total (Acct. 214):	**0**	
Accounts Payable to Associated Companies (234):		
NORTHERN STATES POWER COMPANY MINNESOTA	11,756	**45**
XCEL ENERGY SERVICES	4,546	**46**
MISCELLANEOUS	18	**47**
Total (Acct. 234):	**16,320**	
Customer Deposits (235):		
DEPOSITS ON CUSTOMER ACCOUNTS	1,753	**48**
MISCELLANEOUS	2	**49**
Total (Acct. 235):	**1,755**	

BALANCE SHEET END-OF-YEAR ACCOUNT BALANCES

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (000's) (b)	
Interest Accrued (237):		
FIRST MORTGAGE BONDS 7.375% DUE 12-01-2026	399	**50**
FIRST MORTGAGE BONDS 5.25% DUE 10-01-2018	1,968	**51**
SENIOR NOTES 7.64% DUE 10-01-2008	1,528	**52**
RESOURCE RECOVERY REVENUE BONDS 6% DUE 11-01-2021	186	**53**
FORT MCCOY SYSTEM ACQUISITION 7% DUE 10-15-2030	12	**54**
Total (Acct. 237):	**4,093**	
Dividends Declared (238):		
XCEL ENERGY INC.	10,597	**55**
Total (Acct. 238):	**10,597**	
Matured Long-Term Debt (239):		
NONE		**56**
Total (Acct. 239):	**0**	
Matured Interest (240):		
NONE		**57**
Total (Acct. 240):	**0**	
Tax Collections Payable (241):		
SALES TAX	1,453	**58**
MISCELLANEOUS	78	**59**
Total (Acct. 241):	**1,531**	
Miscellaneous Current and Accrued Liabilities (242):		
ENVIRONMENTAL CLEAN-UP	2,713	**60**
Total (Acct. 242):	**2,713**	

DISTRIBUTION OF TAXES TO ACCOUNTS

1. Explain basis for allocation if used.
2. If the total does not equal taxes accrued, include a reconciling footnote.

Function (a)	Wisconsin License Fee (000's) (b)	Wisconsin Income Tax (000's) (c)	Federal Income Tax (000's) (d)	FICA and Fed. & State Unemployment Tax (000's) (e)		
Accts. 408.1 and 409.1:						
Accts. 408.1 and 409.1: Electric	11,491	2,667	11,653	2,698		1
Accts. 408.1 and 409.1: Gas	1,266	5	(185)	436		2
Accts. 408.1 and 409.1: Water						3
Accts. 408.1 and 409.1: Steam						4
Accts. 408.2 and 409.2		(202)	(1,116)	7		5
Acct. 409.3						6
Clearing Accounts					*	7
Construction						8
Other (specify):						
None						9
Total:	**12,757**	**2,470**	**10,352**	**3,141**		

DISTRIBUTION OF TAXES TO ACCOUNTS (cont.)

PSC Remainder Assessment (000's) (f)	Local Property Tax (000's) (g)	State and Local Taxes Other Than Wisconsin (000's) (h)	Other Taxes (000's) (i)	Total (000's) (j)		
	5	608		**29,122**		**1**
		220		**1,742**		**2**
				0		**3**
				0		**4**
	107	(6)		**(1,210)**		**5**
				0		**6**
			858	**858**	*	**7**
				0		**8**
				0		**9**
0	**112**	**822**	**858**	**30,512**		

DISTRIBUTION OF TAXES TO ACCOUNTS

Distribution of Taxes to Accounts (Page F-53)

General footnotes

```
7. column (i)   Wisconsin use tax   855
                Michigan use tax      3
                Total               858
```

DISTRIBUTION OF TAXES TO ACCOUNTS (cont.)

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INTEREST AND DIVIDEND INCOME (ACCT. 419)

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Interest or Dividend Rate (b)	Amount (000's) (c)	
Interest and Dividend Income (419):			
Revenues:			
ECONOMIC DEVELOPMENT INVESTMENT HUDSON TECHNOLOGY PARK	5.250000%	45	1
CARRYING CHARGE ON DEFERRED MISO DAY 2 COSTS	Various	43	2
ECONOMIC DEVELOPMENT INVESTMENT LA CROSSE INDUSTRIAL PARK	Various	40	3
ECONOMIC DEVELOPMENT INVESTMENT GATEWAY INDUSTRIAL PARK	5.250000%	22	4
MICHIGAN GCR OVER/UNDER RECOVERY	Various	17	5
ECONOMIC DEVELOPMENT INVESTMENT CLEARWATER DEVELOPMENT CORP.	5.250000%	12	6
MISCELLANEOUS	Various	39	7
	Subtotal Revenues:	**218**	
Expenses:			
NONE			8
	Subtotal Expenses:	**0**	
Total (Acct. 419):		**218**	

INTEREST CHARGES (ACCTS. 427, 430 AND 431)

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Amount (000's) (b)	
Interest on Long-Term Debt (427):		
FIRST MORTGAGE BONDS, 7.375%	4,794	**1**
FIRST MORTGAGE BONDS, 5.25%	8,002	**2**
SENIOR NOTES, 7.64%	6,112	**3**
RESOURCE RECOVERY REVENUE BONDS, 6%	1,116	**4**
FORT MCCOY SYSTEM ACQUISITION, 7%	60	**5**
Total (Acct. 427):	**20,084**	
Interest on Debt to Assoc. Companies (430):		
NORTHERN STATES POWER COMPANY MINNESOTA, VARIABLE RATE	1,298	**6**
XCEL ENERGY SERVICES, VARIABLE RATE	71	**7**
Total (Acct. 430):	**1,369**	
Other Interest Expense (431):		
INCOME TAX AUDIT INTEREST	702	**8**
SALES/USE TAX AUDIT INTEREST	12	**9**
CREDIT FACILITIES FEES AMORTIZATION	20	**10**
CUSTOMER DEPOSIT INTEREST	14	**11**
MISCELLANEOUS	(1)	**12**
INCOME TAX REFUND AMORTIZATION PER PSCW RATE ORDER 4220-UR-113	(301)	**13**
Total (Acct. 431):	**446**	
Total:	**21,899**	

INCOME STATEMENT ACCOUNT DETAILS

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Amount (000's) (b)	
Revenues From Merchandising, Jobbing and Contract Work (415):		
Revenues:		
MISCELLANEOUS	24	1
Subtotal Revenues:	**24**	
Expenses:		
NONE		2
Subtotal Expenses:	**0**	
Total (Acct. 415):	**24**	
Less: Costs and Exp. Of Merchandising, Job. & Contract Work (416):		
Revenues:		
NONE		3
Subtotal Revenues:	**0**	
Expenses:		
MISCELLANEOUS	16	4
Subtotal Expenses:	**16**	
Total (Acct. 416):	**(16)**	
Revenues From Nonutility Operations (417):		
Revenues:		
MISCELLANEOUS	22	5
Subtotal Revenues:	**22**	
Expenses:		
MISCELLANEOUS (417.1)	33	6
Subtotal Expenses:	**33**	
Total (Acct. 417):	**(11)**	
Nonoperating Rental Income (418):		
Revenues:		
INCOME FROM MISCELLANEOUS NON-UTILITY RENTAL PROPERTY	84	7
Subtotal Revenues:	**84**	
Expenses:		
Operation Expense		8
Maintenance Expense		9
Rent Expense		10
Depreciation Expense		11
Amortization Expense		12
Other (specify):		
NONE		13
Subtotal Expenses:	**0**	
Total (Acct. 418):	**84**	

INCOME STATEMENT ACCOUNT DETAILS

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Amount (000's) (b)	
Allowance for Other Funds Used During Construction (419.1):		
Revenues:		
NONE		14
Subtotal Revenues:	**0**	
Expenses:		
ELECTRIC	139	15
GAS	20	16
Subtotal Expenses:	**159**	
Total (Acct. 419.1):	**(159)**	
Miscellaneous Nonoperating Income (421):		
Revenues:		
COMMON AFDC - PSCW RATE IN EXCESS OF FERC RATE	345	17
ELECTRIC AFDC - PSCW RATE IN EXCESS OF FERC RATE	337	18
MISCELLANEOUS	2	19
Subtotal Revenues:	**684**	
Expenses:		
NONE		20
Subtotal Expenses:	**0**	
Total (Acct. 421):	**684**	
Gain on Disposition of Property (421.1):		
Revenues:		
GAIN ON DISPOSITION OF LAND	18	21
Subtotal Revenues:	**18**	
Expenses:		
NONE		22
Subtotal Expenses:	**0**	
Total (Acct. 421.1):	**18**	
Loss on Disposition of Property (421.2):		
Revenues:		
NONE		23
Subtotal Revenues:	**0**	
Expenses:		
NONE		24
Subtotal Expenses:	**0**	
Total (Acct. 421.2):	**0**	

INCOME STATEMENT ACCOUNT DETAILS

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Amount (000's) (b)	
Amort. of Debt. Disc. And Expense (428):		
Revenues:		
NONE		**25**
Subtotal Revenues:	**0**	
Expenses:		
FIRST MORTGAGE BONDS SERIES DUE DEC 01, 2026	25	**26**
FIRST MORTGAGE BONDS SERIES DUE OCT 01, 2018	152	**27**
SENIOR NOTES SERIES DUE OCT 01, 2008	76	**28**
RESOURCE RECOVERY FINANCING DUE NOV 01, 2021	6	**29**
Subtotal Expenses:	**259**	
Total (Acct. 428):	**(259)**	
Less: Amort. of Premium on Debt-Credit (429):		
Revenues:		
NONE		**30**
Subtotal Revenues:	**0**	
Expenses:		
NONE		**31**
Subtotal Expenses:	**0**	
Total (Acct. 429):	**0**	
Less: Amortization of Gain on Reaquired Debt-Credit (429.1):		
Revenues:		
NONE		**32**
Subtotal Revenues:	**0**	
Expenses:		
FIRST MORTGAGE BONDS SERIES DUE MAR 01, 2012, REACQUIRED OCT 1983 (428.1)	247	**33**
FIRST MORTGAGE BONDS SERIES DUE JUL 01, 2016, REACQUIRED MAR 1993 (428.1)	132	**34**
FIRST MORTGAGE BONDS SERIES DUE MAR 01, 2018, REACQUIRED MAR 1993 (428.1)	115	**35**
FIRST MORTGAGE BONDS SERIES DUE OCT 01, 2023, REACQUIRED OCT 2003 (428.1)	333	**36**
FIRST MORTGAGE BONDS SERIES DUE APR 01, 2021, REACQUIRED DEC 1996 (428.1)	120	**37**
RESOURCE RECOVERY FINANCING, REACQUIRED NOV 1996 (428.1)	15	**38**
Subtotal Expenses:	**962**	
Total (Acct. 429.1):	**(962)**	
Less: Allowance for Borrowed Funds Used During Construction-Cr. (432):		
Revenues:		
ELECTRIC	119	**39**
GAS	14	**40**
Subtotal Revenues:	**133**	

INCOME STATEMENT ACCOUNT DETAILS

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Amount (000's) (b)	
Less: Allowance for Borrowed Funds Used During Construction-Cr. (432):		
Expenses:		
NONE		41
Subtotal Expenses:	**0**	
Total (Acct. 432):	**133**	
Extraordinary Income (434):		
Revenues:		
NONE		42
Subtotal Revenues:	**0**	
Expenses:		
NONE		43
Subtotal Expenses:	**0**	
Total (Acct. 434):	**0**	
Less: Extraordinary Deductions (435):		
Revenues:		
NONE		44
Subtotal Revenues:	**0**	
Expenses:		
NONE		45
Subtotal Expenses:	**0**	
Total (Acct. 435):	**0**	

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax amoung the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. Provide the substitute page either in the context of a footnote or within the Appendix.

Particulars (Details) (a)	Amount (000's) (b)	
Net Income for the Year	26,573	1
Taxable Income Not Reported on Books		
Contributions in Aid of Construction	3,432	2
Customer Adv - Construction	1,049	3
Sale of Emission Allowance	109	4
Subsidiary Dividends	38	5
TBT Rental Income	17	6
Unbilled Revenue	300	7
Deductions Recorded on Books Not Deducted for Return		
AFDC Equity (Non-CIP)	159	8
Avoided Cost Interest	824	9
Bad Debts	203	10
Book Amortization - Computer Software	5,210	11
Book Amortization - Other	131	12
Book Capitalized Costs	8,462	13
Book Depreciation	45,640	14
Book Unamortized Cost of Retired Debt	962	15
Capitalization of Software Exp - Books	24	16
Clearing Account Book Expense	2,051	17
Club Dues	1	18
Contribution Carryover	(783)	19
Employee Incentive Plans	(26)	20
ESOP Dividend	259	21
Executive Long Term Incentive Plan	234	22
Inventory Reserve	(16)	23
Litigation Reserve	(608)	24
Lobbying Expenses	145	25
Meals, Travel, and Entertainment	62	26
Medical Deductions - Self Insured	67	27
Medicare Reimbursements	165	28
Penalties	46	29
Pension & Benefits Capitalized	323	30
Post Employment Benefits - FAS 112	360	31

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax amoung the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. Provide the substitute page either in the context of a footnote or within the Appendix.

Particulars (Details) (a)	Amount (000's) (b)	
Deductions Recorded on Books Not Deducted for Return		
Prepaid Insurance	649	**32**
PUCIP Adjustment - Electric	519	**33**
Regulatory Liability - IRC Sec 199	166	**34**
Regulatory Reserve	(1,299)	**35**
Regulatory Reserve - Environmental	(5,985)	**36**
Severance Accrual	(38)	**37**
State Tax Deduction Cash vs Accrual	(1,067)	**38**
Vacation Accrual	77	**39**
Income Recorded on Books Not Included in Return		
Book Income - Wisconsin/South Dakota AFDC	425	**40**
Dividends Received Deduction	30	**41**
Deductions on Return Not Charged Against Book Income		
AFDC Debt	133	**42**
ADR Repair Allowance	1,200	**43**
Amortization - Startup Costs	109	**44**
Deferred Compensation Plan Reserve	182	**45**
Environmental Remediation	(2,303)	**46**
FAS 106 Medicare Reimbursement	539	**47**
Gain / (Loss) on Dispositions (Book)	18	**48**
Gain / (Loss) on Dispositions (Tax)	496	**49**
Insurance Fund Income (Cash Value)	105	**50**
Interest Income / Expense on Disputed Tax	(300)	**51**
Internally Developed Software	258	**52**
Lower of Cost or Mkt on Gas Inventory	13	**53**
Pension Expense	2,405	**54**
Post Employment Benefits - FAS 106	(543)	**55**
Post Employement Benefits - FAS 106 Medicare Reimb.	(666)	**56**
PUCIP Adjustment - Gas	675	**57**
Regulatory Asset - MISO Day 2	5,732	**58**
Repair Expenditures	8,763	**59**
State Income Taxes	2,961	**60**
Tax Depreciation	48,211	**61**
Tax Removal Cost Over Book	883	**62**

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax amoung the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. Provide the substitute page either in the context of a footnote or within the Appendix.

Particulars (Details) (a)	Amount (000's) (b)	
Deductions on Return Not Charged Against Book Income		
TBT Interest Expense	1	**63**
Wisconsin Annual License Fee	562	**64**
Reconciling Items: Equity in Earnings of Subsidiary Companies	(59)	**65**
Total Income Tax expense	(15,131)	**66**
Federal Tax Net Income	**33,736**	
Show Computation of Tax:		
Federal Income Tax at 35%	11,807	**67**
Plus:	0	**68**
Prior Period / Audit Adjustments	(1,455)	**69**
TOTAL Federal Income Tax Payable	10,352	* **70**

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Page F-58)

General footnotes

70. Northern States Power Company (Wisconsin) is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2005. The other members of the affiliated group and the Federal Income tax provision of each are:

Xcel Energy Inc.	(38,870)
Northern States Power Company (Minnesota)	81,519
Public Service Company of Colorado	(32,833)
Southwestern Public Service Company	(23,408)
Cheyenne Light, Fuel, and Power Company	798
Xcel Energy Communications Group	(17,787)
Xcel Energy O&M Services Inc.	
Xcel Energy Markets Holdings	1,960
Xcel Energy International	(2,063)
Xcel Energy Retail Holdings	(4,834)
Xcel Energy Ventures	(3,436)
Xcel Energy Wholesale Group	(79,413)
Xcel Energy WYCO Inc.	1,244
WestGas Interstate, Inc.	47
Xcel Energy Services Inc.	4,177

The consolidated Federal Income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Classification (a)	Direct Payroll Distribution (000's) (b)	Allocation of Payroll Charged for Clearing Accounts (000's) (c)	Total (000's) (d)	
Electric				1
Operation				2
Production	5,206			3
Transmission	1,637			4
Distribution	7,226			5
Customer Accounts	4,122			6
Customer Service and Informational	1,128			7
Sales	140			8
Administrative and General	7,750			9
TOTAL Operation (Total of lines 3 thru 9)	**27,209**			10
Maintenance				11
Production	3,338			12
Transmission	865			13
Distribution	2,702			14
Administrative and General				15
TOTAL Maint. (Total of lines 12 thru 15)	**6,905**			16
Total Operation and Maintenance				17
Production (Total of lines 3 and 12)	8,544			18
Transmission (Total of lines 4 and 13)	2,502			19
Distribution (Total of lines 5 and 14)	9,928			20
Customer Accounts (Line 6)	4,122			21
Customer Service and Informational (Line 7)	1,128			22
Sales (Line 8)	140			23
Administrative and General (Total of lines 9 and 15)	7,750			24
TOTAL Operation and Maintenance (Total of lines 18 thru 24)	**34,114**	**1,773**	**35,887**	25
Gas				26
Operation				27
Production-Manufactured Gas	0			28
Production-Nat. Gas (Including Expl. And Dev.)				29
Other Gas Supply	74			30
Storage, LNG Terminaling and Processing	82			31
Transmission	2			32
Distribution	2,271			33
Customer Accounts	1,419			34
Customer Service and Informational	276			35
Sales	43			36
Administrative and General	1,168			37
TOTAL Operation (Total of lines 28 thru 37)	**5,335**			38

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Classification (a)	Direct Payroll Distribution (000's) (b)	Allocation of Payroll Charged for Clearing Accounts (000's) (c)	Total (000's) (d)	
Maintenance				**39**
Production-Manufactured Gas				**40**
Production-Natural Gas				**41**
Other Gas Supply				**42**
Storage, LNG Terminaling and Processing	43			**43**
Transmission				**44**
Distribution	660			**45**
Administrative and General				**46**
TOTAL Maint. (Total of lines 40 thru 46)	**703**			**47**
Total Operation and Maintenance				**48**
Production-Manufactured Gas (Total of lines 28 and 40)	0			**49**
Production-Nat. Gas (Including Expl. And Dev.) (Total lines 29 and 41)				**50**
Other Gas Supply (Total lines 30 and 42)	74			**51**
Storage, LNG Terminaling and Processing (Total lines 31 and 43)	125			**52**
Transmission (Lines 32 and 44)	2			**53**
Distribution (Lines 33 and 45)	2,931			**54**
Customer Accounts (Line 34)	1,419			**55**
Customer Service and Informational (Line 35)	276			**56**
Sales (Line 36)	43			**57**
Administrative and General (Lines 37 and 46)	1,168			**58**
TOTAL Operation and Maint. (Total of lines 49 thru 58)	**6,038**	**314**	**6,352**	**59**
Other Utility Departments				**60**
Operation and Maintenance			**0**	**61**
TOTAL All Utility Dept (Total of lines 25, 59 and 61)	**40,152**	**2,087**	**42,239**	**62**
Utility Plant				**63**
Construction (By Utility Departments)				**64**
Electric Plant	7,923	412	**8,335**	**65**
Gas Plant	1,954	102	**2,056**	**66**
Other			**0**	**67**
TOTAL Construction (Total of lines 65 thru 67)	**9,877**	**514**	**10,391**	**68**
Plant Removal (By Utility Departments)				**69**
Electric Plant	501	26	**527**	**70**
Gas Plant	33	2	**35**	**71**
Other			**0**	**72**
TOTAL Plant Removal (Total of lines 70 thru 72)	**534**	**28**	**562**	**73**
Other Accounts (Specify, provide details in footnote):			**0**	**74**
			0	**75**
Nonutility Operations	35	2	**37**	**76**

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Classification (a)	Direct Payroll Distribution (000's) (b)	Allocation of Payroll Charged for Clearing Accounts (000's) (c)	Total (000's) (d)	
Miscellaneous Income and Deductions	70	3	**73**	**77**
Accounts Receivable	17	1	**18**	**78**
Conservation Programs	821	42	**863**	**79**
			0	**80**
			0	**81**
			0	**82**
			0	**83**
			0	**84**
			0	**85**
			0	**86**
			0	**87**
			0	**88**
			0	**89**
			0	**90**
			0	**91**
			0	**92**
			0	**93**
			0	**94**
TOTAL Other Accounts	**943**	**48**	**991**	**95**
TOTAL SALARIES AND WAGES	**51,506**	**2,677**	**54,183**	**96**

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS

Particulars (a)	Amount (000's) (b)	
Acct. 922--Administrative Expenses Transferred - Cr.:		
Explain basis of computation of credit in this account.		
ADMINISTRATIVE AND GENERAL TRANSFERRED TO CAPITAL	(135)	**1**
SHARED ASSET COSTS	(2,152)	**2**
COSTS THAT WERE BILLED TO OTHERS	(26)	**3**
COMPANY USE OF ELECTRICITY AND GAS	(88)	**4**
Total (Acct. 922):	**(2,401)**	
Acct. 923--Outside Services Employed:		
State total cost, nature of service, and of each person who was paid for services includible in this account, $25,000 or more.		
DELOITTE AND TOUCHE LLP	464	**5**
WELD RILEY PRENN RICCI SC	86	**6**
VERIFICATIONS, INC.	69	**7**
RYBERG AND HAPPE SC	60	**8**
SQUIRE SANDERS AND DEMPSEY LLP	51	**9**
LOOMIS EWERT PARSLEY DAVIS	42	**10**
WE ENERGIES	33	**11**
BRIGGS AND MORGAN	33	**12**
INDIVIDUAL ITEMS UNDER $25,000 & INDIRECT BILLINGS FROM XCEL ENERGY SERVICES	1,315	**13**
Total (Acct. 923):	**2,153**	
Acct. 924--Property Insurance:		
List hereunder major classes of expenses and also state extent (in footnotes) to which utility is self-insured against insurable risks to its property.		
Premiums for insurance	811	**14**
Dividends received from insurance companies--cr.		**15**
Amounts credited to Acct. 261, Property Insurance Reserve		**16**
Other (specify):		
NONE		**17**
Total (Acct. 924):	**811**	
Acct. 925--Injuries and Damages:		
List hereunder major classes of expense. Also, state extent (in footnotes) to which utility is self-insured against risks of injuries and damages to employes or to others.		
Premiums for insurance	1,440	**18**
Dividends received from insurance companies--cr.		**19**
Amounts credited to Acct. 262, Injuries and Damages Reserve		**20**
Expenses of investigating and adjusting claims		**21**
Costs of safety and accident-prevention activities		**22**
Other (specify):		
INJURIES AND DAMAGES EXPENSES	383	**23**
Total (Acct. 925):	**1,823**	
Acct. 926--Employee Pensions and Benefits:		
Report total amount for utility hereunder and show credit for amounts transferred to construction or other accounts, leaving the net balance in Acct. 926.		
Pension accruals or payments to pension fund	(433)	**24**

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS

Particulars (a)	Amount (000's) (b)	
Acct. 926--Employee Pensions and Benefits:		
Report total amount for utility hereunder and show credit for amounts transferred to construction or other accounts, leaving the net balance in Acct. 926.		
Pension payments under unfunded basis		**25**
Employees benefits (life, health, accident & hospital insur. etc.)	7,741	**26**
Expense of educational and recreational activities for employees		**27**
Other (specify):		
NONE		**28**
Total (Acct. 926):	**7,308**	
Acct. 930.2--Miscellaneous General Expenses:		
Industry association dues	310	**29**
Nuclear power research expenses		**30**
Other experimental and general research expenses		**31**
Exp of corporate organization and of servicing outstanding securities of utility		**32**
Directors fees and expenses	134	**33**
Other (specify):		
EXECUTIVE MANAGEMENT EXPENSE	112	**34**
PORTFOLIO STRATEGY AND BUSINESS DEVELOPMENT EXPENSE	118	**35**
BUSINESS PLANNING AND PROCESS EXPENSES	26	**36**
SHAREHOLDERS RELATIONS EXPENSE	96	**37**
OTHER	6	**38**
Total (Acct. 930.2):	**802**	

MISCELLANEOUS GENERAL EXPENSES (ACCT. 930.2) (ELECTRIC)

Description (a)	Amount (000's) (b)	
Industry Association Dues	287	1
Pub & Dist Info to Stkhldrs..expn servicing outstanding Securities	85	2
Directors Fees and Expenses	119	3
Portfolio Strategy and Business Development Expense	104	4
Business Planning and Process Expenses	23	5
Executive Management Expense	98	6
Other	4	7
Total:	**720**	

ELECTRIC OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (000's) (b)	Last Year (000's) (c)	
Operating Revenues			
Sales of Electricity			
Sales of Electricity (440-448)	421,955	380,641	1
(Less) Provision for Rate Refunds (449.1)			2
Total Sales of Electricity	**421,955**	**380,641**	
Other Operating Revenues			
Forfeited Discounts (450)	861	686	3
Miscellaneous Service Revenues (451)	530	542	4
Sales of Water and Water Power (453)	0		5
Rent from Electric Property (454)	694	654	6
Interdepartmental Rents (455)	0		7
Other Electric Revenues (456)	1,929	537	8
Wheeling (456.1)	0		9
Total Other Operating Revenues	**4,014**	**2,419**	
Total Operating Revenues	**425,969**	**383,060**	
Operation and Maintenenance Expenses			
Power Production Expenses (500-558)	255,795	179,404	10
Transmission Expenses (560-578)	(11,567)	(15,980)	11
Distribution Expenses (580-598)	18,724	19,069	12
Customer Accounts Expenses (901-905)	9,143	9,993	13
Customer Service Expenses (907-910)	7,426	7,642	14
Sales Promotion Expenses (911-916)	344	271	15
Administration and General Expenses (920-935)	28,186	25,023	16
Total Operation and Maintenenance Expenses	**308,051**	**225,422**	
Other Expenses			
Depreciation Expense (403)	39,670	38,700	17
Amortization of Limited-Term Utility Plant (404)	4,695	2,117	18
Gain from Disposition of Allowances (411.8)	0		19
Amortization of Other Utility Plant (405)	190	114	20
Amortization of Utility Plant Acquisition Adjustment (406)	0		21
Amortization of Property Losses (407)	(177)	(147)	22
Regulatory Debits (407.3)	0		23
(Less) Regulatory Credits (407.4)	0		24
Taxes Other Than Income Taxes (408.1)	14,686	14,771	25
Income Taxes (409.1)	14,381	27,547	26
Provision for Deferred Income Taxes (410.1, 411.1)	975	6,218	27
Investment Tax Credits, Restored (411.4)	(729)	(733)	28
Total Other Expenses	**73,691**	**88,587**	
Total Operating Expenses	**381,742**	**314,009**	
NET OPERATING INCOME	**44,227**	**69,051**	

ELECTRIC OPERATING REVENUES (ACCT. 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters. In addition to the number of flat rate accounts, except that where setarate meter readings are addedfor billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous period (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
5. See Important Changes During the Year for important new territory added and important rate increases or decreases.
6. For lines 1, 2, 3 and 4, see Sales of Electricity by Rate Schedules for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

	Operating Revenues		Megawatt Hours Sold		Avg. No. Cust. Per Month			
Particulars (a)	**This Year (000's) (b)**	**Last Year (000's) (c)**	**This Year (d)**	**Last Year (e)**	**This Year (f)**	**Last Year (g)**		
Sales of Electricity								
Residential Sales (440)	153,508	139,768	1,928,120	1,844,404	210,077	202,113		1
Farm Sales (441)	0		0		0			2
Small Commercial Sales (442)	165,231	71,624	2,693,432	1,093,113	38,601	33,165		3
Industrial Sales (442)	71,119	142,119	1,482,896	2,937,744	85	1,675	*	4
Public Street & Highway Lighting (444)	3,503	3,477	23,019	24,038	662	673		5
Public Other Sales (445)	1,002	955	12,985	13,117	412	430		6
Sales to Railroads and Railways (446)	0		0		0			7
Interdepartmental Sales (448)	207	131	2,299	1,935	9	9		8
Total Sales to Ultimate Customers	**394,570**	**358,074**	**6,142,751**	**5,914,351**	**249,846**	**238,065**		
Sales for Resale (447)	27,385	22,567	570,113	562,725	10	10		9
Total Sales of Electricity	**421,955**	**380,641**	**6,712,864**	**6,477,076**	**249,856**	**238,075**		
(Less) Provision for Rate Refunds (449.1)								10
Total Revenues Net of Provision for Rate Refunds	**421,955**	**380,641**	**6,712,864**	**6,477,076**	**249,856**	**238,075**		

ELECTRIC OPERATING REVENUES (ACCT. 400)

Electric Operating Revenues (Acct. 400) (Page E-02)

General footnotes

4. In February of 2005, Northern States Power Company Wisconsin converted to a new customer billing system. Prior to conversion, Industrial customers were classified as those customers having minimum demand of 100kw or more. After conversion, Industrial customers were classified as those customers having demand at some point in the last twelve months totaling 1000kw.

OTHER OPERATING REVENUES (ELECTRIC)

1. Report succinct statement of the revenues in each account and show separate totals for each account.
2. Report name of lessee and description of property for major items of rent revenue. Group other rents less than $25,000 by classes.
3. For sales of water and water power, report name of purchaser, purpose for which water used and the development supplying water.
4. Report basis of charges for any interdepartmental rents.
5. Report details of major items in Acct. 456. Group items less than $25,000.

Particulars (a)	Amount (000's) (b)	
Forfeited Discounts (450):		
LATE PAYMENT FEES	861	**1**
Total Forfeited Discounts (450)	**861**	
Miscellaneous Shared Revenues (451):		
SERVICE CONNECTIONS	516	**2**
RETURNED CHECK CHARGE	12	**3**
OTHER MISCELLANEOUS	2	**4**
Total Miscellaneous Shared Revenues (451)	**530**	
Sales of Water & Water Power (453):		
NONE		**5**
Total Sales of Water & Water Power (453)	**0**	
Rent from Electric Property (454):		
RENTAL E-LEASES	311	**6**
VARIOUS TELEPHONE & CABLE TV CO.	383	**7**
Total Rent from Electric Property (454)	**694**	
Interdepartmental Rents (455):		
NONE		**8**
Total Interdepartmental Rents (455)	**0**	
Other Electric Revenues (456):		
SALES AND USE TAX HANDLING	39	**9**
MICHIGAN POWER SUPPLY RECOVERY	1,296	**10**
WISCONSIN POWER AND LIGHT CO.	418	**11**
RESALE FACILITY CHARGE	133	**12**
OTHER MISCELLANEOUS	59	**13**
EEI MUTUAL AID REVENUE	(16)	**14**
Total Other Electric Revenues (456)	**1,929**	
Wheeling (456.1):		
NONE		**15**
Total Wheeling (456.1)	**0**	

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
POWER PRODUCTION EXPENSES					
STEAM POWER GENERATION EXPENSES					
Operation Supervision and Engineering (500)	76	31	**107**	217	**1**
Fuel (501)	174	9,908	**10,082**	8,327	**2**
Steam Expenses (502)	1,090	131	**1,221**	1,191	**3**
Steam from Other Sources (503)			**0**		**4**
(Less) Steam Transferred -- Credit (504)			**0**		**5**
Electric Expenses (505)	514	66	**580**	614	**6**
Miscellaneous Steam Power Expenses (506)	519	(77)	**442**	1,005	**7**
Rents (507)		234	**234**	8	**8**
Allowances (509)			**0**		**9**
Maintenance Supervision and Engineering (510)	59		**59**	72	**10**
Maintenance of Structures (511)	223	204	**427**	377	**11**
Maintenance of Boiler Plant (512)	579	1,366	**1,945**	2,194	**12**
Maintenance of Electric Plant (513)	38	68	**106**	137	**13**
Maintenance of Miscellaneous Steam Plant (514)	310	297	**607**	729	**14**
Total Steam Power Generation Expenses	**3,582**	**12,228**	**15,810**	**14,871**	
NUCLEAR POWER GENERATION EXPENSES					
Operation Supervision and Engineering (517)			**0**		**15**
Fuel (518)			**0**		**16**
Coolants and Water (519)			**0**		**17**
Steam Expenses (520)			**0**		**18**
Steam from Other Sources (521)			**0**		**19**
(Less) Steam Transferred -- Credit (522)			**0**		**20**
Electric Expenses (523)			**0**		**21**
Miscellaneous Nuclear Power Expenses (524)			**0**		**22**
Rents (525)			**0**		**23**
Maintenance Supervision and Engineering (528)			**0**		**24**
Maintenance of Structures (529)			**0**		**25**
Maintenance of Reactor Plant Equipment (530)			**0**		**26**
Maintenance of Electric Plant (531)			**0**		**27**
Maintenance of Miscellaneous Nuclear Plant (532)			**0**		**28**
Total Nuclear Power Generation Expenses	**0**	**0**	**0**	**0**	
HYDRAULIC POWER GENERATION EXPENSES					
Operation Supervision and Engineering (535)	447	132	**579**	595	**29**
Water for Power (536)		544	**544**	685	**30**
Hydraulic Expenses (537)	90	8	**98**	108	**31**
Electric Expenses (538)	1,474	46	**1,520**	1,551	**32**
Miscellaneous Hydraulic Power Generation Expenses (539)	504	1,470	**1,974**	1,854	**33**
Rents (540)		390	**390**	7	**34**
Maintenance Supervision and Engineering (541)	347	275	**622**	130	**35**
Maintenance of Structures (542)	244	387	**631**	1,024	**36**

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
POWER PRODUCTION EXPENSES					
HYDRAULIC POWER GENERATION EXPENSES					
Maintenance of Reservoirs, Dams and Waterways (543)	278	265	**543**	653	**37**
Maintenance of Electric Plant (544)	902	260	**1,162**	1,186	**38**
Maintenance of Miscellaneous Hydraulic Plant (545)	48	193	**241**	175	**39**
Total Hydraulic Power Generation Expenses	**4,334**	**3,970**	**8,304**	**7,968**	
OTHER POWER GENERATION EXPENSES					
Operation Supervision and Engineering (546)	25	11	**36**	85	**40**
Fuel (547)		12,569	**12,569**	6,833	**41**
Generation Expenses (548)	251	6	**257**	319	**42**
Miscellaneous Other Power Generation Expenses (549)	36	91	**127**	205	**43**
Rents (550)		52	**52**	2	**44**
Maintenance Supervision and Engineering (551)	4	5	**9**	6	**45**
Maintenance of Structures (552)	69	94	**163**	259	**46**
Maintenance of Generating and Electric Plant (553)	221	381	**602**	1,246	**47**
Maintenance of Miscellaneous Other Power Generation Plant (554)	16	25	**41**	328	**48**
Total Other Power Generation Expenses	**622**	**13,234**	**13,856**	**9,283**	
OTHER POWER SUPPLY EXPENSES					
Purchased Power (555)			**0**		**49**
System Control and Load Dispatching (556)	6	21	**27**	7	**50**
Other Expenses (557)		217,798	**217,798**	147,275	**51**
Precertification Expenses (558)			**0**		**52**
Total Other Power Supply Expenses	**6**	**217,819**	**217,825**	**147,282**	
Total Power Production Expenses	**8,544**	**247,251**	**255,795**	**179,404**	
TRANSMISSION EXPENSES					
Operation Supervision and Engineering (560)	711	147	**858**	1,352	**53**
Load Dispatching (561)	607	335	**942**	877	**54**
Station Expenses (562)	135	47	**182**	155	**55**
Overhead Lines Expenses (563)	137	114	**251**	356	**56**
Underground Lines Expenses (564)		1	**1**	0	**57**
Transmission of Electricity by Others (565)			**0**		**58**
Miscellaneous Transmission Expenses (566)	47	(16,802)	**(16,755)**	(23,021)	**59**
Rents (567)		290	**290**	9	**60**
Maintenance Supervision and Engineering (568)	62		**62**	0	**61**
Maintenance of Structures (569)			**0**		**62**
Maintenance of Station Equipment (570)	648	266	**914**	686	**63**
Maintenance of Overhead Lines (571)	124	1,474	**1,598**	3,604	**64**
Maintenance of Underground Lines (572)			**0**		**65**
Maintenance of Miscellaneous Transmission Plant (573)	31	59	**90**	2	**66**

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
TRANSMISSION EXPENSES					
Precertification Expenses (578)			**0**		**67**
Total Transmission Expenses	**2,502**	**(14,069)**	**(11,567)**	**(15,980)**	
DISTRIBUTION EXPENSES					
Operation Supervision and Engineering (580)	991	216	**1,207**	1,086	**68**
Load Dispatching (581)	585	85	**670**	630	**69**
Station Expenses (582)	204	93	**297**	287	**70**
Overhead Line Expenses (583)	722	14	**736**	1,061	**71**
Underground Line Expenses (584)	1,135	349	**1,484**	1,441	**72**
Street Lighting and Signal System Expenses (585)	147	77	**224**	339	**73**
Meter Expenses (586)	804	(113)	**691**	1,145	**74**
Customer Installations Expenses (587)	320	(273)	**47**	1,124	**75**
Miscellaneous Expenses (588)	2,334	2,502	**4,836**	4,554	**76**
Rents (589)		796	**796**	30	**77**
Maintenance Supervision and Engineering (590)	8	185	**193**	201	**78**
Maintenance of Structures (591)			**0**		**79**
Maintenance of Station Equipment (592)	466	369	**835**	557	**80**
Maintenance of Overhead Lines (593)	1,459	4,060	**5,519**	5,480	**81**
Maintenance of Underground Lines (594)	591	301	**892**	698	**82**
Maintenance of Line Transformers (595)	54	79	**133**	312	**83**
Maintenance of Street Lighting and Signal Systems (596)	80	38	**118**	68	**84**
Maintenance of Meters (597)	43	2	**45**	51	**85**
Maintenance of Miscellaneous Distribution Plant (598)	1		**1**	5	**86**
Total Distribution Expenses	**9,944**	**8,780**	**18,724**	**19,069**	
CUSTOMER ACCOUNTS EXPENSES					
Supervision (901)	17	(3)	**14**	16	**87**
Meter Reading Expenses (902)	2,060	583	**2,643**	2,569	**88**
Customer Records and Collection Expenses (903)	2,045	2,025	**4,070**	5,293	**89**
Uncollectible Accounts (904)		1,625	**1,625**	1,630	**90**
Miscellaneous Customer Accounts Expenses (905)		791	**791**	485	**91**
Total Customer Accounts Expenses	**4,122**	**5,021**	**9,143**	**9,993**	
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
Supervision (907)			**0**		**92**
Customer Assistance Expenses (908)	1,128	6,129	**7,257**	7,306	**93**
Informational and Instructional Expenses (909)		169	**169**	214	**94**
Miscellaneous Customer Service and Informational Expenses (910)			**0**	122	**95**
Total Customer Service and Informational Expenses	**1,128**	**6,298**	**7,426**	**7,642**	

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
SALES EXPENSES					
Supervision (911)			**0**		**96**
Demonstrating and Selling Expenses (912)	132	212	**344**	271	**97**
Advertising Expenses (913)			**0**		**98**
Miscellaneous Sales Expenses (916)			**0**		**99**
Total Sales Expenses	**132**	**212**	**344**	**271**	
ADMINISTRATIVE AND GENERAL EXPENSES					
Administrative and General Salaries (920)	7,591		**7,591**	6,763	**100**
Office Supplies and Expenses (921)		7,777	**7,777**	7,665	**101**
(Less) Administrative Expenses Transferred -- Credit (922)		2,086	**2,086**	1,618	**102**
Outside Services Employed (923)		1,900	**1,900**	2,132	**103**
Property Insurance (924)		717	**717**	934	**104**
Injuries and Damages (925)	318	1,240	**1,558**	2,035	**105**
Employee Pensions and Benefits (926)	6,294		**6,294**	2,653	**106**
Franchise Requirements (927)			**0**		**107**
Regulatory Commission Expenses (928)		853	**853**	598	**108**
(Less) Duplicate Charges -- Credit (929)		274	**274**	321	**109**
General Advertising Expenses (930.1)		512	**512**	649	**110**
Miscellaneous General Expenses (930.2)	176	544	**720**	1,386	**111**
Rents (931)		2,586	**2,586**	2,133	**112**
Maintenance of General Plant (935)		38	**38**	14	**113**
Total Administrative and General Expenses	**14,379**	**13,807**	**28,186**	**25,023**	
Total Operation and Maintenance Expenses	**40,751**	**267,300**	**308,051**	**225,422**	

ELECTRIC EXPENSES

Report all amounts on the basis and in conformity with the uniform system of accounts and accounting directives prescribed by this commission. Allocate "Total Operations" amounts jurisdictionally between Wisconsin (PSCW) jurisdiction and all other jurisdiction.

Particulars (a)	Wisconsin Jurisdictional Operations Labor (000's) (b)	Wisconsin Jurisdictional Operations Other (000's) (c)	Other Jurisdictional Operations Labor (000's) (d)	Other Jurisdictional Operations Other (000's) (e)	Total Operations (000's) (f)	
Operation and Maintenenance Expenses						
Power Production Expenses (500-558)	8,360	241,723	184	5,528	255,795	**1**
Transmission Expenses (560-578)	2,448	(13,768)	54	(301)	(11,567)	**2**
Distribution Expenses (580-598)	9,647	8,459	297	321	18,724	**3**
Customer Accounts Expenses (901-905)	3,965	4,849	157	172	9,143	**4**
Customer Service Expenses (907-910)	1,085	6,279	43	19	7,426	**5**
Sales Promotion Expenses (911-916)	127	204	5	8	344	**6**
Administration and General Expenses (920-935)	13,975	13,426	404	381	28,186	**7**
Total Operation and Maintenenance Expenses	**39,607**	**261,172**	**1,144**	**6,128**	**308,051**	
Other Expenses						
Depreciation Expense (403)		38,629		1,041	39,670	**8**
Amortization of Limited-Term Utility Plant (404)		4,564		131	4,695	**9**
Gain from Disposition of Allowances (411.8)					0	**10**
Amortization of Other Utility Plant (405)		185		5	190	**11**
Amortization of Utility Plant Acquisition Adjustment (406)					0	**12**
Amortization of Property Losses (407)		(177)			(177)	**13**
Regulatory Debits (407.3)					0	**14**
(Less) Regulatory Credits (407.4)					0	**15**
Taxes Other Than Income Taxes (408.1)		14,318		368	14,686	**16**
Income Taxes (409.1)		14,151		230	14,381	**17**
Provision for Deferred Income Taxes (410.1, 411.1)		453		522	975	**18**
Investment Tax Credits, Restored (411.4)		(711)		(18)	(729)	**19**
Total Other Expenses	**0**	**71,412**	**0**	**2,279**	**73,691**	
Total Operating Expenses	**39,607**	**332,584**	**1,144**	**8,407**	**381,742**	

SALES FOR RESALE (ACCOUNT 447)

1. Report all sales for resale (i.e., sales to purchaser other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule.
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractural terms and conditions of the service as follows:
   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
   LF - for long-term service. "Long-term" means five years or longer and "firm" means that the service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the needs of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.
   SF - for short-term service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
   LU - for Long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availibility and reliability of designated unit.

Name of Company or Public Authority (Explain Affiliation in Footnote) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		
Village of Bangor, WI	RQ	95	6	7		*	1
City of Barron, WI	RQ	103	12	14			2
City of Bloomer, WI	RQ	106	9	10			3
Village of Cadott, WI	RQ	104	3	3			4
City of Cornell, WI	RQ	59	2	3			5
City of Medford, WI	RQ	111	24	26			6
City of Rice Lake, WI	RQ	109	30	33			7
City of Spooner, WI	RQ	105	6	7			8
Village of Trempealeau, WI	RQ	108	3	4			9
City of Wakefield, MI	RQ	107	2	3			10
Unbilled	RQ						11

SALES FOR RESALE (ACCOUNT 447) (cont.)

IU - for Intermediate-term service from a designated generating unit. The same as LU service except that "Intermediate-term" means longer than one year but less than five years.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm serviceregardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
5. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, leave columns (d), (e) and (f) blank. Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
7. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
8. Footnote entries as required and provide explanations following all required data.

		Revenue					
	MegaWatt Hours Sold (g)	Demand Charges (000's) (h)	Energy Charges (000's) (i)	Other Charges (000's) (j)	Total Charges (000's) (k)		
	34,991	542	849	358	1,749	*	1
	83,994	1,022	1,990	595	3,606		2
	50,949	714	1,180	492	2,386		3
	14,856	210	344	145	699		4
	13,386	186	314	133	634		5
	140,577	2,045	3,434	1,418	6,897		6
	172,207	2,553	4,220	1,738	8,511		7
	34,364	484	811	341	1,636		8
	14,888	229	350	150	730		9
	13,437	186	309	131	626		10
	(3,536)	0	(89)	0	(89)		11
Subtotal RQ:	**570,113**	**8,171**	**13,712**	**5,501**	**27,385**		
Subtotal non-RQ:	**0**	**0**	**0**	**0**	**0**		
Total:	**570,113**	**8,171**	**13,712**	**5,501**	**27,385**		

SALES FOR RESALE (ACCOUNT 447)

Sales for Resale (Account 447) (Page E-06)

General footnotes

1. **$5,876,404 of other revenue in column (j) is related to Fuel Cost Adjustments.**

SALES FOR RESALE (ACCOUNT 447) (cont.)

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SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (000's) (c)	MWh (d)	Avg. No. of Customers (e)	
Wisconsin Geographical Operations					
Residential Sales (440)					
	B00	103	1,319	525	1
	B01	132,160	1,639,580	184,194	2
	B02	8,524	129,172	7,982	3
	B03	8	116	22	4
	B04	7,388	96,747	4,102	5
	B08	4	57	6	6
	B11	22	516	53	7
	B30	395	3,380	5,076	8
	B37	2	30	10	9
Subtotal - Billed Sales		**148,606**	**1,870,917**	**201,970**	
Unbilled Residential Sales		680	1,641		10
Total Sales for Residential Sales (440)		**149,286**	**1,872,558**	**201,970**	
Farm Sales (441)					
					11
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Farm Sales					12
Total Sales for Farm Sales (441)		**0**	**0**	**0**	
Small Commercial Sales (442)					
	B05	296	4,540	187	13
	B06	28,251	349,548	25,062	14
	B07	10	131	19	15
	B08	5	71	11	16
	B09	735	8,273	1,423	17
	B10	62,874	998,742	5,967	18
	B11	135	3,247	119	19
	B12	1,477	26,871	72	20
	B13	95,945	1,791,583	789	21
	B14	31,194	667,330	133	22
	B30	437	4,690	3,516	23
	B38	2	12		24
	B60	4,922	122,049	8	25

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (000's) (c)	MWh (d)	Avg. No. of Customers (e)	
Wisconsin Geographical Operations					
Small Commercial Sales (442)					
	IND	(70,129)	(1,461,436)	(83) *	26
	W16	564	14,038	9	27
Subtotal - Billed Sales		**156,718**	**2,529,689**	**37,232**	
Unbilled Small Commercial Sales		4,892	107,003		28
Total Sales for Small Commercial Sales (442)		**161,610**	**2,636,692**	**37,232**	
Industrial Sales (442)					
	IND	70,129	1,461,436	83 *	29
Subtotal - Billed Sales		**70,129**	**1,461,436**	**83**	
Unbilled Industrial Sales					30
Total Sales for Industrial Sales (442)		**70,129**	**1,461,436**	**83**	
Public Street & Highway Lighting (444)					
	B31	2,531	12,193	407	31
	B32	5	61	3	32
	B33	398	7,366	102	33
	B34	26	182	9	34
	B35	204	707	69	35
	B36	24	574	26	36
	B38	24	80	29	37
Subtotal - Billed Sales		**3,212**	**21,163**	**645**	
Unbilled Public Street & Highway Lighting		132	1,000		38
Total Sales for Public Street & Highway Lighting (444)		**3,344**	**22,163**	**645**	
Public Other Sales (445)					
	B20	2		86	39
	B22	912	11,923	291	40
Subtotal - Billed Sales		**914**	**11,923**	**377**	
Unbilled Public Other Sales		32	248		41
Total Sales for Public Other Sales (445)		**946**	**12,171**	**377**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (000's) (c)	MWh (d)	Avg. No. of Customers (e)	
Wisconsin Geographical Operations					
Sales to Railroads and Railways (446)					
					42
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Sales to Railroads and Railways					**43**
Total Sales for Sales to Railroads and Railways (446)		**0**	**0**	**0**	
Interdepartmental Sales (448)					
		206	2,290	8	**44**
Subtotal - Billed Sales		**206**	**2,290**	**8**	
Unbilled Interdepartmental Sales					**45**
Total Sales for Interdepartmental Sales (448)		**206**	**2,290**	**8**	
Total Wisconsin		**385,521**	**6,007,310**	**240,315**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (000's) (c)	MWh (d)	Avg. No. of Customers (e)	
Out-of-State Geographical Operations					
Residential Sales (440)					
	C01	4,071	53,557	7,779	**46**
	C02	92	1,505	118	**47**
	C04	18	133	210	**48**
Subtotal - Billed Sales		**4,181**	**55,195**	**8,107**	
Unbilled Residential Sales		41	367		**49**
Total Sales for Residential Sales (440)		**4,222**	**55,562**	**8,107**	
Farm Sales (441)					
					50
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Farm Sales					**51**
Total Sales for Farm Sales (441)		**0**	**0**	**0**	
Small Commercial Sales (442)					
	C04	19	198	133	**52**
	C09	27	316	53	**53**
	C10	1,065	13,636	1,027	**54**
	C11	5	61	2	**55**
	C12	1,218	18,225	130	**56**
	C13	1,045	19,546	17	**57**
	C20	1,009	21,923	7	**58**
	C21	9	153	2	**59**
	IND	(990)	(21,460)	(2) *	**60**
Subtotal - Billed Sales		**3,407**	**52,598**	**1,369**	
Unbilled Small Commercial Sales		214	4,142		**61**
Total Sales for Small Commercial Sales (442)		**3,621**	**56,740**	**1,369**	
Industrial Sales (442)					
	IND	990	21,460	2 *	**62**
Subtotal - Billed Sales		**990**	**21,460**	**2**	
Unbilled Industrial Sales					**63**
Total Sales for Industrial Sales (442)		**990**	**21,460**	**2**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (000's) (c)	MWh (d)	Avg. No. of Customers (e)	
Out-of-State Geographical Operations					
Public Street & Highway Lighting (444)					
	C30	149	788	17	**64**
Subtotal - Billed Sales		**149**	**788**	**17**	
Unbilled Public Street & Highway Lighting		10	68		**65**
Total Sales for Public Street & Highway Lighting (444)		**159**	**856**	**17**	
Public Other Sales (445)					
	C32	55	815	35	**66**
Subtotal - Billed Sales		**55**	**815**	**35**	
Unbilled Public Other Sales		1	(1)		**67**
Total Sales for Public Other Sales (445)		**56**	**814**	**35**	
Sales to Railroads and Railways (446)					
					68
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Sales to Railroads and Railways					**69**
Total Sales for Sales to Railroads and Railways (446)		**0**	**0**	**0**	
Interdepartmental Sales (448)					
		1	9	1	**70**
Subtotal - Billed Sales		**1**	**9**	**1**	
Unbilled Interdepartmental Sales					**71**
Total Sales for Interdepartmental Sales (448)		**1**	**9**	**1**	
Total Out-of-State		**9,049**	**135,441**	**9,531**	
TOTAL UTILITY		**394,570**	**6,142,751**	**249,846**	

SALES OF ELECTRICITY BY RATE SCHEDULE

Sales of Electricity by Rate Schedule (Page E-08)

General footnotes

Due to a billing system conversion in 2005, we no longer have a break down by rate code of Small Commercial and Industrial. In this schedule, all rate codes are reported under Small Commercial, and Industrial is reported using rate code IND.

STATE OF MICHIGAN
Estimated Additional Revenue Collected Through Fuel Clause Adjustment:

Rate Code		Revenue
C01	$	84,084
C02		2,363
C04		121
Total Residential	$	86,568
C04	$	177
C09		495
C10		22,081
C11		96
C12		29,000
C13		30,687
C20		34,419
C21		241
Total C&I	$	117,196
C30	$	1,237
Total Street Lighting	$	1,237
C32	$	1,279
Total Other Sales	$	1,279
TOTAL MICHIGAN	$	206,280

STATE OF WISCONSIN
Estimated Additional Revenue Collected Through Fuel Surcharge Mechanism:

Rate Code		Revenue
B00	$	5,860
B01		7,345,950
B02		561,876
B03		665
B04		424,670
B08		275
B11		2,158
B30		8,812
B37		124
Total Residential	$	8,350,390
B05	$	20,152
B06		1,575,247
B07		586
B08		292
B09		37,034
B10		4,543,943
B11		13,841
B12		123,944
B13		8,359,125
B14		3,229,643
B20		2,698
B30		13,681
B60		572,791
W16		44,642
Total C&I	$	18,537,619
B31	$	56,562
B32		280
B33		34,062
B34		848
B35		3,226
B36		2,409

SALES OF ELECTRICITY BY RATE SCHEDULE

B38		**361**
Total Street Lighting	**$**	**97,748**
B22	**$**	**53,227**
Total Other Sales	**$**	**53,227**
TOTAL WISCONSIN	**$**	**27,038,984**

NUCLEAR FUEL MATERIALS (ACCOUNT 120.1 THROUGH 120.6 AND 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, explain in footnote the amount of nuclear fuel leased, the quantity used and the quantity on hand, and the costs incurred under such leasing arrangements.

Description of Item (a)	Balance First of Year (000's) (b)	Changes during Year: Additions (000's) (c)	Changes during Year: Amortization (000's) (d)	Changes during Year: Other Reductions (000's) (e)	Balance End of Year (000's) (f)	
Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					0	1
Fabrication					0	2
Nuclear Materials					0	3
Allowance for Funds Used during Construction					0	4
(Other Overhead Construction Costs, provide details in footnote)					0	5
SUBTOTAL (Total 2 thru 5)					0	6
Nuclear Fuel Materials and Assemblies					0	7
In Stock (120.2)					0	8
In Reactor (120.3)					0	9
SUBTOTAL (Total 8 & 9)					0	10
Spent Nuclear Fuel (120.4)					0	11
Nuclear Fuel Under Capital Leases (120.6)					0	12
(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					0	13
TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					0	14
Estimated net Salvage Value of Nuclear Materials in line 9					0	15
Estimated net Salvage Value of Nuclear Materials in line 11					0	16
Est Net Salvage Value of Nuclear Materials in Chemical Processing					0	17
Nuclear Materials held for Sale (157)					0	18
Uranium					0	19
Plutonium					0	20
Other (provide details in footnote):					0	21
TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					0	22

PURCHASED POWER (ACCOUNT 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractural terms and conditions of the service as follows:
   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
   LF - for long-term service. "Long-term" means five years or longer and "firm" means that the service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the needs of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.
   SF - for short-term service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
   LU - for Long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availibility and reliability of designated unit.
   IU - for Intermediate-term service from a designated generating unit. The same as LU service except that "Intermediate-term" means longer than one year but less than five years.
   EX - for exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

				Actual Demand (MW)			
Name of Company or Public Authority (Footnote Affiliations) (a)	**Statistical Classifi-cation (b)**	**FERC Rate Schedule or Tariff Number (c)**	**Average Monthly Billing Demand (MW) (d)**	**Average Monthly NCP Demand (e)**	**Average Monthly CP Demand (f)**		
Northern States Power Company - MN **							1
Northern States Power Company - MN **	AD					*	2
** All transactions involving							3
Purchased Power and Sales to Other							4
are included in and shared through the							5
Interchange Agreement with utility							6
affiliate (NSP-MN).							7
Total							

PURCHASED POWER (ACCOUNT 555) (cont.)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm serviceregardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, leave columns (d), (e) and (f) blank. Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (1) includes credits or charges other than the incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER					
MegaWatt Hours Purchased (g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (000's) (j)	Energy Charges (000's) (k)	Other Charges (000's) (l)	Total (j+k+l) of Settlement (000's) (m)		
6,351,005	0	0	0	0	219,383	**219,383**		1
0	0	0	0	0	4,145	**4,145**	*	2
0	0	0	0	0	0	**0**		3
0	0	0	0	0	0	**0**		4
0	0	0	0	0	0	**0**		5
0	0	0	0	0	0	**0**		6
0	0	0	0	0	0	**0**		7
6,351,005	**0**	**0**	**0**	**0**	**223,528**	**223,528**		

PURCHASED POWER (ACCOUNT 555)

Purchased Power (Account 555) (Page E-10)

General footnotes

2. Adjustments primarily relate to true-up of estimated December 2004 energy requirements to actual energy requirements and true-up of estimated 2004 Interchange Agreement Fixed Charges to actual 2004 Interchange Agreement Fixed Charges.

PURCHASED POWER (ACCOUNT 555) (cont.)

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ELECTRIC UTILITY PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (000's) (b)	Additions During Year (000's) (c)	Retirements During Year (000's) (d)	Adjustments Increase or (Decrease) (000's) (e)	Balance End of Year (000's) (f)		
INTANGIBLE PLANT							
Organization (301)	0				**0**		**1**
Franchises and Consents (302)	3,013				**3,013**		**2**
Miscellaneous Intangible Plant (303)	1,439	901		83	**2,423**		**3**
Total Intangible Plant	**4,452**	**901**	**0**	**83**	**5,436**		
STEAM PRODUCTION PLANT							
Land and Land Rights (310)	74				**74**		**4**
Structures and Improvements (311)	13,289	261			**13,550**		**5**
Boiler Plant Equipment (312)	64,347	1,955	34		**66,268**		**6**
Engines and Engine-Driven Generators (313)	0				**0**		**7**
Turbogenerator Units (314)	7,771				**7,771**		**8**
Accessory Electric Equipment (315)	5,480	106			**5,586**		**9**
Miscellaneous Power Plant Equipment (316)	2,292	124			**2,416**		**10**
Asset Retirement Costs for Steam Production (317)	0				**0**		**11**
Total Steam Production Plant	**93,253**	**2,446**	**34**	**0**	**95,665**		
NUCLEAR PRODUCTION PLANT							
Land and Land Rights (320)	0				**0**		**12**
Structures and Improvements (321)	0				**0**		**13**
Reactor Plant Equipment (322)	0				**0**		**14**
Turbogenerator Units (323)	0				**0**		**15**
Accessory Electric Equipment (324)	0				**0**		**16**
Miscellaneous Power Plant Equipment (325)	0				**0**		**17**
Asset Retirement Costs for Nuclear Production (326)	0				**0**		**18**
Total Nuclear Production Plant	**0**	**0**	**0**	**0**	**0**		
HYDRAULIC PRODUCTION PLANT							
Land and Land Rights (330)	2,441				**2,441**		**19**
Structures and Improvements (331)	16,533	1,041		35	**17,609**		**20**
Reservoirs, Dams and Waterways (332)	125,189	1,777		(35)	**126,931**		**21**
Water Wheels, Turbines and Generators (333)	36,091	148			**36,239**		**22**
Accessory Electric Equipment (334)	23,878	(11)			**23,867**	*	**23**
Miscellaneous Power Plant Equipment (335)	6,113	96			**6,209**		**24**
Roads, Railroads and Bridges (336)	0				**0**		**25**
Asset Retirement Costs for Hydraulic Production (337)					**0**		**26**
Total Hydraulic Production Plant	**210,245**	**3,051**	**0**	**0**	**213,296**		

ELECTRIC UTILITY PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (000's) (b)	Additions During Year (000's) (c)	Retirements During Year (000's) (d)	Adjustments Increase or (Decrease) (000's) (e)	Balance End of Year (000's) (f)		
OTHER PRODUCTION PLANT							
Land and Land Rights (340)	192				**192**		**27**
Structures and Improvements (341)	2,405	67			**2,472**		**28**
Fuel Holders, Producers and Accessories (342)	2,697	542	73		**3,166**		**29**
Prime Movers (343)	31,952	(80)			**31,872**	*	**30**
Generators (344)	18,533	147			**18,680**		**31**
Accessory Electric Equipment (345)	6,071	244			**6,315**		**32**
Miscellaneous Power Plant Equipment (346)	1,401	83			**1,484**		**33**
Asset Retirement Costs for Other Production (347)					**0**		**34**
Total Other Production Plant	**63,251**	**1,003**	**73**	**0**	**64,181**		
TRANSMISSION PLANT							
Land and Land Rights (350)	12,847	23	1		**12,869**		**35**
Structures and Improvements (352)	6,816	69			**6,885**		**36**
Station Equipment (353)	124,854	3,992	332		**128,514**		**37**
Towers and Fixtures (354)	2,532	77	72	167	**2,704**		**38**
Poles and Fixtures (355)	88,343	783	95	(167)	**88,864**		**39**
Overhead Conductors and Devices (356)	98,260	150	24		**98,386**		**40**
Underground Conduit (357)	75				**75**		**41**
Underground Conductors and Devices (358)	220	5			**225**		**42**
Roads and Trails (359)	104				**104**		**43**
Asset Retirement Costs for Transmission Plant (359.1)					**0**		**44**
Total Transmission Plant	**334,051**	**5,099**	**524**	**0**	**338,626**		
DISTRIBUTION PLANT							
Land and Land Rights (360)	1,111	24			**1,135**		**45**
Structures and Improvements (361)	7,188	(502)	3		**6,683**	*	**46**
Station Equipment (362)	79,048	4,257	112		**83,193**		**47**
Storage Battery Equipment (363)					**0**		**48**
Poles, Towers and Fixtures (364)	73,791	4,031	251		**77,571**		**49**
Overhead Conductors and Devices (365)	86,340	4,474	776		**90,038**		**50**
Underground Conduit (366)	11,595	635	5		**12,225**		**51**
Underground Conductors and Devices (367)	64,031	4,238	175		**68,094**		**52**
Line Transformers (368)	75,602	2,458	436		**77,624**		**53**
Services (369)	66,253	2,577	113		**68,717**		**54**
Meters (370)	19,312	1,026	1,388		**18,950**		**55**
Installations on Customers' Premises (371)	6,460	22	400		**6,082**		**56**
Leased Property on Customers' Premises (372)					**0**		**57**
Street Lighting and Signal Systems (373)	6,021	686	55		**6,652**		**58**

ELECTRIC UTILITY PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (000's) (b)	Additions During Year (000's) (c)	Retirements During Year (000's) (d)	Adjustments Increase or (Decrease) (000's) (e)	Balance End of Year (000's) (f)	
DISTRIBUTION PLANT						
Asset Retirement Costs for Distribution Plant (374)	0	200			**200**	**59**
Total Distribution Plant	**496,752**	**24,126**	**3,714**	**0**	**517,164**	
GENERAL PLANT						
Land and Land Rights (389)	166				**166**	**60**
Structures and Improvements (390)	6,816	238		255	**7,309**	**61**
Office Furniture and Equipment (391)	1,295	245	77		**1,463**	**62**
Transportation Equipment (392)	3,331	1,265			**4,596**	**63**
Stores Equipment (393)	137				**137**	**64**
Tools, Shop and Garage Equipment (394)	5,220	766			**5,986**	**65**
Laboratory Equipment (395)	2,890				**2,890**	**66**
Power Operated Equipment (396)	2,113	55			**2,168**	**67**
Communication Equipment (397)	5,670	155			**5,825**	**68**
Miscellaneous Equipment (398)	18				**18**	**69**
Other Tangible Property (399)					**0**	**70**
Asset Retirement Costs for General Plant (399.1)					**0**	**71**
Total General Plant	**27,656**	**2,724**	**77**	**255**	**30,558**	
Total utility plant in service	**1,229,660**	**39,350**	**4,422**	**338**	**1,264,926**	
Electric Plant Purchased (102)					**0**	**72**
(Less) Electric Plant Sold (102)					**0**	**73**
Experimental Plant Unclassified (103)					**0**	**74**
Total utility plant in service	**1,229,660**	**39,350**	**4,422**	**338**	**1,264,926**	

ELECTRIC UTILITY PLANT IN SERVICE

Electric Utility Plant in Service (Page E-12)

General footnotes

23. Negative additions due to 106 reclass to different 101 plant account.
30. Negative additions due to 106 reclass to different 101 plant account.
46. Negative additions due to 106 reclass to different 101 plant account.

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (000's) (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (000's) (d)	Accruals During Year: Additional Amount (000's) (e)	
INTANGIBLE PLANT					
Organization (301)					1
Franchises and Consents (302)					2
Miscellaneous Intangible Plant (303)					3
Total Intangible Plant	**0**		**0**	**0**	
STEAM PRODUCTION PLANT					
Land and Land Rights (310)					4
Structures and Improvements (311)	9,941	2.02%	271		5
Boiler Plant Equipment (312)	35,712	2.70%	1,763		6
Engines and Engine-Driven Generators (313)					7
Turbogenerator Units (314)	5,797	2.08%	162		8
Accessory Electric Equipment (315)	3,551	2.67%	147		9
Miscellaneous Power Plant Equipment (316)	605	4.02%	95		10
Asset Retirement Costs for Steam Production (317)					11
Total Steam Production Plant	**55,606**		**2,438**	**0**	
NUCLEAR PRODUCTION PLANT					
Land and Land Rights (320)					12
Structures and Improvements (321)					13
Reactor Plant Equipment (322)					14
Turbogenerator Units (323)					15
Accessory Electric Equipment (324)					16
Miscellaneous Power Plant Equipment (325)					17
Asset Retirement Costs for Nuclear Production (326)					18
Total Nuclear Production Plant	**0**		**0**	**0**	
HYDRAULIC PRODUCTION PLANT					
Land and Land Rights (330)					19
Structures and Improvements (331)	6,627	2.57%	439		20
Reservoirs, Dams and Waterways (332)	54,770	2.58%	3,257		21
Water Wheels, Turbines and Generators (333)	14,643	2.31%	835		22
Accessory Electric Equipment (334)	8,534	2.51%	598		23
Miscellaneous Power Plant Equipment (335)	1,435	2.90%	179		24
Roads, Railroads and Bridges (336)					25
Asset Retirement Costs for Hydraulic Production (337)					26
Total Hydraulic Production Plant	**86,009**		**5,308**	**0**	
OTHER PRODUCTION PLANT					
Land and Land Rights (340)					27
Structures and Improvements (341)	2,255	1.19%	29		28
Fuel Holders, Producers and Accessories (342)	2,349	2.23%	66		29

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

Account (a)	Book Cost of Plant Retired (000's) (f)	Cost of Removal (000's) (g)	Salvage (000's) (h)	Adjustments Increase or (Decrease) (000's) (i)	Balance End of Year (000's) (j)	
301					**0**	**1**
302					**0**	**2**
303					**0**	**3**
	0	**0**	**0**	**0**	**0**	
310					**0**	**4**
311					**10,212**	**5**
312	34	56			**37,385**	**6**
313					**0**	**7**
314					**5,959**	**8**
315					**3,698**	**9**
316					**700**	**10**
317					**0**	**11**
	34	**56**	**0**	**0**	**57,954**	
320					**0**	**12**
321					**0**	**13**
322					**0**	**14**
323					**0**	**15**
324					**0**	**16**
325					**0**	**17**
326					**0**	**18**
	0	**0**	**0**	**0**	**0**	
330					**0**	**19**
331					**7,066**	**20**
332					**58,027**	**21**
333					**15,478**	**22**
334			5		**9,137**	**23**
335			1		**1,615**	**24**
336					**0**	**25**
337					**0**	**26**
	0	**0**	**6**	**0**	**91,323**	
340					**0**	**27**
341					**2,284**	**28**
342	73	74			**2,268**	**29**

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (000's) (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (000's) (d)	Accruals During Year: Additional Amount (000's) (e)	
OTHER PRODUCTION PLANT					
Prime Movers (343)	28,421	0.88%	280		**30**
Generators (344)	15,832	1.32%	246		**31**
Accessory Electric Equipment (345)	5,262	1.48%	92		**32**
Miscellaneous Power Plant Equipment (346)	380	9.08%	131		**33**
Asset Retirement Costs for Other Production (347)					**34**
Total Other Production Plant	**54,499**		**844**	**0**	
TRANSMISSION PLANT					
Land and Land Rights (350)					**35**
Structures and Improvements (352)	1,008	2.63%	195		**36**
Station Equipment (353)	52,736	3.29%	4,138		**37**
Towers and Fixtures (354)	1,884	2.30%	61		**38**
Poles and Fixtures (355)	30,368	2.88%	2,544		**39**
Overhead Conductors and Devices (356)	31,399	2.75%	2,703		**40**
Underground Conduit (357)	14	2.63%	2		**41**
Underground Conductors and Devices (358)	116	2.75%	7		**42**
Roads and Trails (359)	84	2.50%	3		**43**
Asset Retirement Costs for Transmission Plant (359.1)					**44**
Total Transmission Plant	**117,609**		**9,653**	**0**	
DISTRIBUTION PLANT					
Land and Land Rights (360)					**45**
Structures and Improvements (361)	705	2.63%	192		**46**
Station Equipment (362)	36,034	3.50%	2,821		**47**
Storage Battery Equipment (363)					**48**
Poles, Towers and Fixtures (364)	35,584	3.43%	2,603		**49**
Overhead Conductors and Devices (365)	33,236	3.43%	3,028		**50**
Underground Conduit (366)	4,215	2.63%	313		**51**
Underground Conductors and Devices (367)	13,806	2.57%	1,692		**52**
Line Transformers (368)	25,933	3.00%	2,301		**53**
Services (369)	37,984	5.20%	3,491		**54**
Meters (370)	8,319	4.55%	905		**55**
Installations on Customers' Premises (371)	6,108	7.92%	51		**56**
Leased Property on Customers' Premises (372)	0				**57**
Street Lighting and Signal Systems (373)	5,544	6.47%	406		**58**
Asset Retirement Costs for Distribution Plant (374)					**59**
Total Distribution Plant	**207,468**		**17,803**	**0**	
GENERAL PLANT					
Land and Land Rights (389)					**60**
Structures and Improvements (390)	1,999	2.86%	198		**61**
Office Furniture and Equipment (391)	745	5.00%	89		**62**

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

Account (a)	Book Cost of Plant Retired (000's) (f)	Cost of Removal (000's) (g)	Salvage (000's) (h)	Adjustments Increase or (Decrease) (000's) (i)	Balance End of Year (000's) (j)	
343					**28,701**	**30**
344					**16,078**	**31**
345					**5,354**	**32**
346					**511**	**33**
347					**0**	**34**
	73	**74**	**0**	**0**	**55,196**	
350	1		19	(18)	**0**	**35**
352					**1,203**	**36**
353	332	44			**56,498**	**37**
354	72			2	**1,875**	**38**
355	95	102	252	(2)	**32,965**	**39**
356	24	48	169		**34,199**	**40**
357					**16**	**41**
358					**123**	**42**
359					**87**	**43**
359.1					**0**	**44**
	524	**194**	**440**	**(18)**	**126,966**	
360					**0**	**45**
361	3	0		9	**903**	**46**
362	112	13	(1)	(9)	**38,720**	**47**
363					**0**	**48**
364	251	463	11		**37,484**	**49**
365	776	451	80		**35,117**	**50**
366	5	(1)			**4,524**	**51**
367	175	47	31		**15,307**	**52**
368	436	41	21		**27,778**	**53**
369	113	69			**41,293**	**54**
370	1,388				**7,836**	**55**
371	400	1			**5,758**	**56**
372					**0**	**57**
373	55	79			**5,816**	**58**
374					**0**	**59**
	3,714	**1,163**	**142**	**0**	**220,536**	
389					**0**	**60**
390				2	**2,199**	**61**
391	77				**757**	**62**

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (000's) (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (000's) (d)	Accruals During Year: Additional Amount (000's) (e)		
GENERAL PLANT						
Transportation Equipment (392)	1,488	0.00%	326		*	63
Stores Equipment (393)	110	5.00%	7			64
Tools, Shop and Garage Equipment (394)	2,434	5.00%	268			65
Laboratory Equipment (395)	1,536	5.00%	144			66
Power Operated Equipment (396)	764	0.00%	142		*	67
Communication Equipment (397)	5,052	10.00%	457			68
Miscellaneous Equipment (398)	13	5.00%	1			69
Other Tangible Property (399)	212	0.00%		381	*	70
Asset Retirement Costs for General Plant (399.1)				0		71
Retirement Work in Progress						72
Total General Plant	**14,353**		**1,632**	**381**		
Electric Plant Purchased (102)						73
(Less) Electric Plant Sold (102)						74
Experimental Plant Unclassified (103)						75
Total accum. prov. for depreciation	**535,544**		**37,678**	**381**		

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

Account (a)	Book Cost of Plant Retired (000's) (f)	Cost of Removal (000's) (g)	Salvage (000's) (h)	Adjustments Increase or (Decrease) (000's) (i)	Balance End of Year (000's) (j)		
392					1,814	*	63
393					117		64
394					2,702		65
395					1,680		66
396					906	*	67
397					5,509		68
398					14		69
399					593	*	70
399.1					0		71
RWIP					0		72
	77	0	0	2	16,291		
102					0		73
102b					0		74
103					0		75
	4,422	1,487	588	(16)	568,266		

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Accumulated Provision for Depreciation - Electric (Page E-13)

General footnotes

63. Various rates are in this account.
67. Various rates are in this account.
70. Various rates are in this account.

Balance End of Year includes $3,875 (OOO's) of electric retirement work in progress.

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Report data for plant in service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, sand nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as shown on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Item (a)	Plant Name: Bay Front (b)			Plant Name: Flambeau Station (c)			
Kind of Plant (Internal Comb, Gas Turb, Nuclear)			Steam			Gas Turbine	1
Type of Constr (Conventional, Outdoor, Boiler, etc.)			Conventional			Conventional	2
Year Originally Constructed			1917			1969	3
Year Last Unit was Installed			1958			1969	4
Total Installed Cap (Max Gen Name Plate Ratings-MW)			72.00			19.30	5
Net Peak Demand on Plant - MW (60 minutes)			73			0	6
Plant Hours Connected to Load			8,760			0	7
Net Continuous Plant Capability (Megawatts)			73			0	8
When Not Limited by Condenser Water			73			0	9
When Limited by Condenser Water			68			0	10
Average Number of Employees			35			1	11
Net generation, Exclusive of Plant Use - KWh (000's)			337,076			297	12
Cost of Plant: Land and Land Rights (000's)			67			10	13
Structures and Improvements (000's)			6,834			395	14
Equipment Costs (000's)			43,244			4,169	15
Asset Retirement Costs (000's)			0			0	16
Total Cost (000's)			**50,145**			**4,574**	**17**
Cost per KW of Installed Capacity (line 17/5) Including			696			237	18
Production Expenses: Oper, Supv, & Engr (000's)			13			1	19
Fuel (000's)			10,834			95	20
Coolants and Water (Nuclear Plants Only) (000's)			0			0	21
Steam Expenses (000's)			921			0	22
Steam From Other Sources (000's)			0			0	23
Steam Transferred (Cr) (000's)			0			0	24
Electric Expenses (000's)			373			21	25
Misc Steam (or Nuclear) Power Expenses (000's)			197			1	26
Rents (000's)			148			13	27
Allowances (000's)			0			0	28
Maintenance Supervision and Engineering (000's)			59			0	29
Maintenance of Structures (000's)			281			9	30
Maintenance of Boiler (or reactor) Plant (000's)			841			0	31
Maintenance of Electric Plant (000's)			104			186	32
Maintenance of Misc Steam (or Nuclear) Plant (000's)			268			10	33
Total Production Expense (000's)			**14,039**			**336**	**34**
Expenses per Net KWh			**0.0416**			**1.1281**	**35**
Fuel Kind (Coal, Gas, Oil, or Nuclear)	Wood	Coal	Gas	Oil	Gas	Composite	36
Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Ton	Ton	MCF	Barrel	MCF		37
Quantity (Units) of Fuel Burned	142,604	155,049	279,950	19,927	8,072	0	38
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	5,444	9,830	1,017	138,912	1,000	0	39
Avg Cost of Fuel/Unit, as Delvd f.o.b. during year	9.873	42.248	7.823	44.667	9.119	0.000	40
Average Cost of Fuel per Unit Burned	9.873	47.014	7.823	44.667	9.119	0.000	41
Average Cost of Fuel Burned per Million BTU	0.907	2.149	7.692	7.656	9.117	8.744	42
Average Cost of Fuel Burned per KWh Net Gen	0.000	32.300	0.000	0.000	0.000	46.931	43
Average BTU per KWh Net Generation	0.000	14.494	0.000	0.000	0.000	5.367	44
Footnotes							45

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and other expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

	Plant Name: French Island (d)			**Plant Name: French Island (e)**			**Plant Name: Wheaton (f)**			
			Gas Turbine			Steam			Gas Turbine	**1**
			Heated Individually			Conventional			Heated Individually	**2**
			1973			1940			1973	**3**
			1974			1948			1974	**4**
			175.00			35.00			322.00	**5**
			0			0			0	**6**
			0			0			0	**7**
			0			17			0	**8**
			0			17			0	**9**
			0			17			0	**10**
			0			29			4	**11**
			14,279			73,594			54,694	**12**
			0			7			182	**13**
			501			6,716			1,576	**14**
			16,499			38,797			39,856	**15**
			0			0			0	**16**
			17,000			**45,520**			**41,614**	**17**
			97			1,301			129	**18**
			2			94			33	**19**
			2,976			(752)			9,498	**20**
			0			0			0	**21**
			0			300			0	**22**
			0			0			0	**23**
			0			0			0	**24**
			45			206			190	**25**
			7			244			119	**26**
			4			86			36	**27**
			0			0			0	**28**
			2			0			7	**29**
			8			146			146	**30**
			0			1,104			0	**31**
			107			3			309	**32**
			0			340			31	**33**
			3,151			**1,771**			**10,369**	**34**
			0.2207			**0.0241**			**0.1896**	**35**
		Oil		Wood	RDF	Gas	Gas	Oil	Composite	**36**
		Barrel		Ton	Ton	MCF	MCF	Barrel		**37**
	0	44,070	0	57,547	53,487	3,234	772,124	63,588	0	**38**
	0	140,000	0	6,624	6,038	1,008	1,004	140,923	0	**39**
	0.000	67.529	0.000	8.262	-31.501	8.861	8.285	48.770	0.000	**40**
	0.000	67.529	0.000	17.861	-31.501	8.861	8.285	48.770	0.000	**41**
	0.000	11.484	0.000	0.624	-2.609	8.792	8.249	8.240	8.246	**42**
	0.000	208.403	0.000	0.000	-8.538	0.000	0.000	0.000	175.502	**43**
	0.000	18.146	0.000	0.000	19.180	0.000	0.000	0.000	21.282	**44**
										45

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (nameplate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Item (a)	FERC Licensed Project No. 2440 Name: Chippewa Falls (b)	FERC Licensed Project No. 2639 Name: Cornell (c)	
Kind of Plant (Run-of-River or Storage)	Peaking	Peaking	1
Plant Construction Type (Conventional or Outdoor)	Conventional	Conventional	2
Year Originally Constructed	1928	1976	3
Year Last Unit was Installed	1928	1977	4
Total Installed Cap (Gen Name Plate Ratings-MW)	24.00	33.00	5
Net Peak Demand on Plant - MW (60 minutes)	0	0	6
Plant Hours Connected to Load	0	0	7
Net Continuous Plant Capability (Megawatts)			8
(a) Under Most Favorable Oper Conditions	21	30	9
(b) Under the Most Adverse Oper Conditions	19	30	10
Average Number of Employees	0	1	11
Net generation, Exclusive of Plant Use - KWh (000's)	49,204	65,377	12
Cost of Plant			13
Land and Land Rights (000's)	113	54	14
Structures and Improvements (000's)	514	2,438	15
Reservoirs, Dams and Waterways (000's)	3,174	12,823	16
Equipment Costs (000's)	9,389	4,885	17
Roads, Railroads and Bridges (000's)	0	0	18
Asset Retirement Costs (000's)	0	0	19
Total Cost (000's)	**13,190**	**20,200**	20
Cost per KW of Installed Capacity (line 20/5)	**549.5833**	**612.1212**	21
Production Expenses			22
Operation Supervision and Engineering (000's)	36	48	23
Water for Power (000's)	58	73	24
Hydraulic Expenses (000's)	0	54	25
Electric Expenses (000's)	63	15	26
Misc Hydraulic Power Generation Expense (000's)	129	195	27
Rents (000's)	20	22	28
Maintenance Supervision and Engineering (000's)	45	59	29
Maintenance of Structures (000's)	2	14	30
Maint. of Reservoirs, Dams and Waterways (000's)	2	5	31
Maintenance of Electric Plant (000's)	32	13	32
Maintenance of Misc Hydraulic Plant (000's)	12	18	33
Total Production Expense (000's)	**399**	**516**	34
Expenses per Net KWh	**0.0081**	**0.0079**	35
Footnotes			36

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

	FERC Licensed Project No. 1982 Name: Holcombe (d)	FERC Licensed Project No. 2491 Name: Jim Falls (e)	FERC Licensed Project No. 0 Name: St. Croix Falls (f)	
	Run-of-River	Peaking	Peaking	1
	Conventional	Conventional	Conventional	2
	1950	1923	1905	3
	1950	1988	1911	4
	33.90	55.50	23.15	5
	0	0	0	6
	0	0	0	7
				8
	35	56	24	9
	35	56	24	10
	1	1	5	11
	73,218	94,548	115,588	12
				13
	231	851	85	14
	779	9,690	878	15
	7,034	69,534	1,545	16
	3,649	26,297	5,086	17
	0	0	0	18
	0	0	0	19
	11,693	**106,372**	**7,594**	20
	344.9263	**1,916.6126**	**328.0346**	21
				22
	54	69	87	23
	78	103	0	24
	1	1	6	25
	20	66	89	26
	198	271	235	27
	23	27	57	28
	66	86	105	29
	5	7	196	30
	20	2	43	31
	70	36	354	32
	20	33	30	33
	555	**701**	**1,202**	34
	0.0076	**0.0074**	**0.0104**	35
				36

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (nameplate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Item (a)	FERC Licensed Project No. 2567 Name: Wissota (b)	(c)	
Kind of Plant (Run-of-River or Storage)	Peaking		1
Plant Construction Type (Conventional or Outdoor)	Conventional		2
Year Originally Constructed	1917		3
Year Last Unit was Installed	1917		4
Total Installed Cap (Gen Name Plate Ratings-MW)	36.00		5
Net Peak Demand on Plant - MW (60 minutes)	0		6
Plant Hours Connected to Load	0		7
Net Continuous Plant Capability (Megawatts)			8
(a) Under Most Favorable Oper Conditions	36		9
(b) Under the Most Adverse Oper Conditions	36		10
Average Number of Employees	7		11
Net generation, Exclusive of Plant Use - KWh (000's)	103,123		12
Cost of Plant			13
Land and Land Rights (000's)	383		14
Structures and Improvements (000's)	1,406		15
Reservoirs, Dams and Waterways (000's)	14,541		16
Equipment Costs (000's)	4,689		17
Roads, Railroads and Bridges (000's)	0		18
Asset Retirement Costs (000's)	0		19
Total Cost (000's)	**21,019**		20
Cost per KW of Installed Capacity (line 20/5)	**583.8611**		21
Production Expenses			22
Operation Supervision and Engineering (000's)	143		23
Water for Power (000's)	107		24
Hydraulic Expenses (000's)	0		25
Electric Expenses (000's)	472		26
Misc Hydraulic Power Generation Expense (000's)	317		27
Rents (000's)	108		28
Maintenance Supervision and Engineering (000's)	93		29
Maintenance of Structures (000's)	247		30
Maint. of Reservoirs, Dams and Waterways (000's)	26		31
Maintenance of Electric Plant (000's)	385		32
Maintenance of Misc Hydraulic Plant (000's)	36		33
Total Production Expense (000's)	**1934**		34
Expenses per Net KWh	**0.0188**		35
Footnotes			36

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

	(d)	(e)	(f)	
				1
				2
				3
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				36

GENERATING PLANT STATISTICS (SMALL PLANTS)

1. Small generating plants are steam plants of less than 25,000 Kw, internal combustion and gas-turbine plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Plant Name (a)	Year Originally Constructed (b)	Installed Capacity Name Plate Rating (in MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (000's) (f)		
Apple River	1901	2.85	2.0	13,667	2,531	*	1
Cedar Falls	1910	6.00	7.0	28,788	4,803	*	2
Eau Claire Dells	1907	9.50	8.0	34,960	4,059	*	3
Menomonie	1958	5.40	5.0	21,808	4,299	*	4
Riverdale	1905	0.60	0.0	2,661	801	*	5
Trego	1926	1.20	1.0	6,540	1,195	*	6
Big Falls	1922	7.78	7.0	29,981	3,215	*	7
Hayward	1910	0.20	0.0	1,504	251	*	8
Ladysmith	1941	3.00	2.0	9,004	4,999	*	9
Saxon Falls	1912	1.20	1.0	11,022	1,329	*	10
Superior Falls	1917	1.32	1.0	12,313	1,764	*	11
Thornapple	1927	1.40	1.0	7,957	2,349	*	12
White River	1907	1.00	0.0	4,333	1,272	*	13

GENERATING PLANT STATISTICS (SMALL PLANTS) (cont.)

Plant Cost (Including Asset Retirement Costs) Per MW (000's) (g)	Operation Excluding Fuel (000's) (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million BTU) (l)		
		Fuel (000's) (i)	Maintenance (000's) (j)				
888	52	0	116		0	*	1
801	229	0	155		0	*	2
427	560	0	55		0	*	3
796	167	0	107		0	*	4
1,335	12	0	56		0	*	5
996	118	0	93		0	*	6
413	221	0	247		0	*	7
1,254	24	0	10		0	*	8
1,666	82	0	33		0	*	9
1,108	94	0	27		0	*	10
1,336	114	0	30		0	*	11
1,678	71	0	33		0	*	12
1,272	110	0	172		0	*	13

GENERATING PLANT STATISTICS (SMALL PLANTS)

Generating Plant Statistics (Small Plants) (Page E-19)

General footnotes

The numbers in the Net Peak Demand MW column are being rounded by the software.

GENERATING PLANT STATISTICS (SMALL PLANTS) (cont.)

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ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Particulars (a)		MegaWatt Hours (b)	
Source of Energy			
Generation (excluding Station Use):			
Steam		410,669	1
Nuclear		0	2
Hydro-Conventional		685,596	3
Hydro-Pumped Storage		0	4
Other		69,270	5
Less Energy for Pumping		0	6
Net Generation		**1,165,535**	7
Purchases		6,351,005	8
Power Exchanges:	Received	0	9
	Delivered	0	10
	Net Exchanges	**0**	11
Transmission for Others (Wheeling):	Received	0	12
	Delivered	0	13
	Net Transmission for Other	**0**	14
Transmission by Others Losses		0	15
Total Source of Energy		**7,516,540**	16
			17
Disposition of Energy			18
Sales to Ultimate Consumers (Including Interdepartmental Sales)		6,142,751	19
Requirements Sales For Resale		570,113	20
Non-Requirements Sales For Resale		0	21
Energy Furnished Without Charge		0	22
Energy Used by the Company (Electric Dept. Only, Excluding Station Use)		4,313	23
Total Energy Losses		799,363	24
Total Disposition of Energy		**7,516,540**	25

MONTHLY PEAKS AND OUTPUT

1. Report hereunder the information called for pertaining to simultaneous peaks established monthly (in Megawatt-hours).
2. Monthly peak col. (b) should be respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system.
3. State type of monthly peak reading (instantaneous (0), 15, 30, or 60 minutes integrated).
4. Monthly output should be the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling.
5. If the utility has two or more power systems not physically connected, the information called for below should be furnished for each system.
6. Report Time Ending col. (e) in military time.

Month (a)		Monthly Peak MW (b)	Day of Week (c)	Date (MM/DD/YYYY) (d)	Time Ending (HH:MM) (e)	Type of Reading (0, 15, 30, 60) (f)	Monthly Output (MWh) (g)	
January	01	1,124	Tuesday	01/18/2005	18:00	60	675,838	1
February	02	1,060	Wednesday	02/16/2005	20:00	60	597,613	2
March	03	1,033	Wednesday	03/02/2005	20:00	60	632,635	3
April	04	927	Tuesday	04/26/2005	09:00	60	539,236	4
May	05	986	Monday	05/02/2005	13:00	60	582,667	5
June	06	1,301	Monday	06/27/2005	15:00	60	654,759	6
July	07	1,290	Wednesday	07/13/2005	14:00	60	697,494	7
August	08	1,285	Tuesday	08/02/2005	13:00	60	681,159	8
September	09	1,190	Monday	09/12/2005	14:00	60	605,659	9
October	10	1,160	Monday	10/03/2005	20:00	60	587,772	10
November	11	1,090	Thursday	11/17/2005	18:00	60	591,865	11
December	12	1,217	Monday	12/19/2005	18:00	60	669,843	12
	Totals:	**13,663**					**7,516,540**	

System Name: Northern States Power Co. (Wisconsin)

GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)		
Located in Wisconsin and operated by utility								
COAL								
Bayfront	4	20.00	ST	22.00	22.00	72,202.00	*	1
Bayfront	5	20.00	ST	22.00	22.00	107,602.00	*	2
Bayfront	6	32.00	ST	29.00	29.00	157,271.00	*	3
GAS								
Flambeau Station	1	19.30	GT	14.33	19.50	297.00		4
Wheaton	1	54.00	GT	56.04	71.00	10,729.00		5
Wheaton	2	54.00	GT	63.17	72.00	9,735.00		6
Wheaton	3	54.00	GT	55.70	71.00	11,108.00		7
Wheaton	4	54.00	GT	56.59	71.00	8,597.00		8
BIO GAS								
	NONE							9
NUCLEAR								
	NONE							10
OIL								
	NONE							11
French Island	3	87.50	GT	70.13	90.13	8,212.00		12
French Island	4	87.50	GT	71.23	89.73	6,067.00		13
Wheaton	5	53.00	GT	60.81	78.00	7,764.00		14
Wheaton	6	53.00	GT	60.11	78.00	6,761.00		15
HYDRO								
Apple River	1	0.90	HY	0.91	0.91	5,134.00		16
Apple River	2	0.90	HY	0.00	0.00	0.00	*	17
Apple River	3	1.05	HY	0.89	0.89	3,762.00		18
Apple River	4	1.05	HY	1.04	1.04	4,771.00		19
Big Falls	1	2.64	HY	2.30	2.30	14,701.00		20
Big Falls	2	2.64	HY	2.30	2.30	10,472.00		21
Big Falls	3	2.50	HY	2.50	2.50	4,808.00		22
Cedar Falls	1	2.00	HY	2.55	2.55	8,549.00		23
Cedar Falls	2	2.00	HY	2.20	2.20	10,931.00		24
Cedar Falls	3	2.00	HY	2.25	2.25	9,308.00		25
Chippewa Falls	1	4.00	HY	3.68	3.68	6,331.00		26
Chippewa Falls	2	4.00	HY	3.70	3.70	7,074.00		27
Chippewa Falls	3	4.00	HY	3.75	3.75	12,353.00		28
Chippewa Falls	4	4.00	HY	3.65	3.65	7,805.00		29

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)		
Coal (Tons)	**Other**	**Gas (Mcf.)**					
155,049.00	142,604.00	279,950.00	9,830	5,444	1,017	*	1
n/a							
0.00	0.00	0.00	0	0	0	*	2
						*	3
Gas (Mcf.)	**Oil (Bbls.)**						
8,072.00	19,927.00	0.00	1,000	138,912	0		4
198,074.00	4,613.00	0.00	1,004	140,923	0		5
188,280.00	3,588.00	0.00	1,004	140,923	0		6
211,915.00	3,935.00	0.00	1,004	140,923	0		7
173,855.00	2,770.00		1,004	140,923			8
							9
							10
							11
Oil (Bbls.)							
0.00	0.00	0.00	0	0	0		12
0.00	0.00	0.00	0	0	0		13
0.00	0.00	0.00	0	0	0		14
0.00	0.00	0.00	0	0	0		15
0.00	0.00	0.00	0	0	0		16
0.00	0.00	0.00	0	0	0	*	17
0.00	0.00	0.00	0	0	0		18
0.00	0.00	0.00	0	0	0		19
0.00	0.00	0.00	0	0	0		20
0.00	0.00	0.00	0	0	0		21
0.00	0.00	0.00	0	0	0		22
0.00	0.00	0.00	0	0	0		23
0.00	0.00	0.00	0	0	0		24
0.00	0.00	0.00	0	0	0		25
0.00	0.00	0.00	0	0	0		26
0.00	0.00	0.00	0	0	0		27
0.00	0.00	0.00	0	0	0		28
0.00	0.00	0.00	0	0	0		29

GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)	
Located in Wisconsin and operated by utility							
HYDRO							
Chippewa Falls	5	4.00	HY	2.53	2.53	12,642.00	**30**
Chippewa Falls	6	4.00	HY	3.69	3.69	2,999.00	**31**
Cornell	1	11.00	HY	9.70	9.70	27,763.00	**32**
Cornell	2	11.00	HY	10.00	10.00	8,151.00	**33**
Cornell	3	11.00	HY	10.18	10.18	23,148.00	**34**
Cornell	4	0.75	HY	0.65	0.65	6,315.00	**35**
Dells	1	2.00	HY	2.34	2.34	5,125.00	**36**
Dells	2	1.60	HY	1.19	1.19	4,056.00	**37**
Dells	3	1.60	HY	1.20	1.20	5,641.00	**38**
Dells	4	1.60	HY	1.29	1.29	6,504.00	**39**
Dells	5	1.60	HY	1.20	1.20	6,970.00	**40**
Dells	6	0.50	HY	0.59	0.59	3,346.00	**41**
Dells	7	0.60	HY	0.73	0.73	3,318.00	**42**
Hayward	1	0.20	HY	0.20	0.20	1,504.00	**43**
Holcombe	1	11.30	HY	11.74	11.74	20,832.00	**44**
Holcombe	2	11.30	HY	11.73	11.73	26,616.00	**45**
Holcombe	3	11.30	HY	11.71	11.71	25,771.00	**46**
Jim Falls	HC1	27.50	HY	27.90	27.90	49,951.00	**47**
Jim Falls	HC2	27.50	HY	27.91	27.91	41,585.00	**48**
Jim Falls	MSF	0.50	HY	0.51	0.51	3,013.00	**49**
Ladysmith	1	0.90	HY	0.90	0.90	2,079.00	**50**
Ladysmith	2	0.90	HY	0.87	0.87	4,253.00	**51**
Ladysmith	3	1.20	HY	1.11	1.11	2,671.00	**52**
Menomonie	1	2.70	HY	2.65	2.65	11,059.00	**53**
Menomonie	2	2.70	HY	2.73	2.73	10,750.00	**54**
Riverdale	1	0.30	HY	0.32	0.32	1,350.00	**55**
Riverdale	2	0.30	HY	0.30	0.30	1,311.00	**56**
Saxon Falls	1	0.60	HY	0.70	0.55	4,833.00	**57**
Saxon Falls	2	0.60	HY	0.80	0.65	6,189.00	**58**
St Croix Falls	1	2.50	HY	2.99	2.99	15,422.00	**59**
St Croix Falls	2	2.50	HY	2.60	2.60	15,058.00	**60**
St Croix Falls	3	2.50	HY	2.80	2.80	7,895.00	**61**
St Croix Falls	4	2.45	HY	3.09	3.09	14,849.00	**62**
St Croix Falls	5	3.40	HY	3.19	3.19	14,331.00	**63**
St Croix Falls	6	3.40	HY	2.70	2.70	12,404.00	**64**
St Croix Falls	7	3.20	HY	3.09	3.09	20,082.00	**65**
St Croix Falls	8	3.20	HY	3.09	3.09	15,546.00	**66**
Superior Falls	1	0.66	HY	0.95	0.75	6,251.00	**67**
Superior Falls	2	0.66	HY	0.90	0.70	6,062.00	**68**
Thornapple	1	0.70	HY	0.72	0.72	4,000.00	**69**
Thornapple	2	0.70	HY	0.78	0.78	3,957.00	**70**
Trego	1	0.70	HY	0.80	0.80	5,494.00	**71**

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)	
0.00	0.00	0.00	0	0	0	**30**
0.00	0.00	0.00	0	0	0	**31**
0.00	0.00	0.00	0	0	0	**32**
0.00	0.00	0.00	0	0	0	**33**
0.00	0.00	0.00	0	0	0	**34**
0.00	0.00	0.00	0	0	0	**35**
0.00	0.00	0.00	0	0	0	**36**
0.00	0.00	0.00	0	0	0	**37**
0.00	0.00	0.00	0	0	0	**38**
0.00	0.00	0.00	0	0	0	**39**
0.00	0.00	0.00	0	0	0	**40**
0.00	0.00	0.00	0	0	0	**41**
0.00	0.00	0.00	0	0	0	**42**
0.00	0.00	0.00	0	0	0	**43**
0.00	0.00	0.00	0	0	0	**44**
0.00	0.00	0.00	0	0	0	**45**
0.00	0.00	0.00	0	0	0	**46**
0.00	0.00	0.00	0	0	0	**47**
0.00	0.00	0.00	0	0	0	**48**
0.00	0.00	0.00	0	0	0	**49**
0.00	0.00	0.00	0	0	0	**50**
0.00	0.00	0.00	0	0	0	**51**
0.00	0.00	0.00	0	0	0	**52**
0.00	0.00	0.00	0	0	0	**53**
0.00	0.00	0.00	0	0	0	**54**
0.00	0.00	0.00	0	0	0	**55**
0.00	0.00	0.00	0	0	0	**56**
0.00	0.00	0.00	0	0	0	**57**
0.00	0.00	0.00	0	0	0	**58**
0.00	0.00	0.00	0	0	0	**59**
0.00	0.00	0.00	0	0	0	**60**
0.00	0.00	0.00	0	0	0	**61**
0.00	0.00	0.00	0	0	0	**62**
0.00	0.00	0.00	0	0	0	**63**
0.00	0.00	0.00	0	0	0	**64**
0.00	0.00	0.00	0	0	0	**65**
0.00	0.00	0.00	0	0	0	**66**
0.00	0.00	0.00	0	0	0	**67**
0.00	0.00	0.00	0	0	0	**68**
0.00	0.00	0.00	0	0	0	**69**
0.00	0.00	0.00	0	0	0	**70**
0.00	0.00	0.00	0	0	0	**71**

GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)	
Located in Wisconsin and operated by utility							
HYDRO							
Trego	2	0.50	HY	0.60	0.60	1,046.00	**72**
White River	1	0.50	HY	0.44	0.30	1,434.00	**73**
White River	2	0.50	HY	0.42	0.30	2,899.00	**74**
Wissota	1	6.00	HY	5.94	5.94	12,369.00	**75**
Wissota	2	6.00	HY	5.96	5.96	11,921.00	**76**
Wissota	3	6.00	HY	6.10	6.10	12,775.00	**77**
Wissota	4	6.00	HY	5.96	5.96	37,700.00	**78**
Wissota	5	6.00	HY	5.96	5.96	19,789.00	**79**
Wissota	6	6.00	HY	6.08	6.08	8,569.00	**80**
WIND							
							81
OTHER RENEWABLES (PHOTOVOLTAICS, FUEL CELLS)							
French Island	1	17.50	ST	15.00	15.00	35,998.00	* **82**
French Island	2	17.50	ST	14.00	14.00	37,595.00	* **83**
DISTRIBUTED GENERATORS							
							84
	MW TOTAL:	**872.10**		**854.36**	**985.65**	**1,165,535.00**	
	Located in Wisconsin and operated by utility						
Generating Units operated by others or located outside of Wisconsin							
OTHER							
	NONE						**85**
	MW TOTAL:	**0.00**		**0.00**	**0.00**	**0.00**	
	Generating Units located outside of Wisconsin or operated by others (less joint plant amounts)						

Total Generator Nameplate Capacity: **872.10** **Total Net Generation:** **1,165,535.00**

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)	
0.00	0.00	0.00	0	0	0	72
0.00	0.00	0.00	0	0	0	73
0.00	0.00	0.00	0	0	0	74
0.00	0.00	0.00	0	0	0	75
0.00	0.00	0.00	0	0	0	76
0.00	0.00	0.00	0	0	0	77
0.00	0.00	0.00	0	0	0	78
0.00	0.00	0.00	0	0	0	79
0.00	0.00	0.00	0	0	0	80
						81
						* 82
0.00	0.00	0.00	0	0	0	* 83
						84
935,245.00	**177,437.00**	**279,950.00**				
						85
0.00	**0.00**	**0.00**				

GENERATION SUMMARY WORKSHEET

Generation Summary Worksheet (Page E-23)

General footnotes

1-3. BayFront has a common steam header that feeds all three turbines. Fuel usage by turbine unit is not available. Numbers shown are for the total plant.

17. Not In Service

1,82-83. Primary Fuel Wood Tons

82-83. Secondary Fuel RDF Tons

GENERATION SUMMARY WORKSHEET (cont.)

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COAL CONTRACT INFORMATION - SPECIFICATION AND COSTS

Vendor Name/ Term of Agreement/ Plant Name (a) - (c)	Total Cost of Coal Delivered (000's) (d)	Total Units Delivered (2,000 lb. tons) (e)	Avg. Btu's per lb. of Coal Delivered (f)	Avg. Percent Moisture of Coal Delivered (g)	Avg. Percent Sulfur of Coal Delivered (h)	Avg. Percent Ash of Coal Delivered (i)		
ARCH-COAL / 04-01-2005 to 12-31-2005								
BAY FRONT	1,345	36,346	11,325	10.55%	0.33%	8.40%		1
C. REISS / 01-01-2005 to 12-31-2005								
BAY FRONT	342	100,867					*	2
KIEWIT MINE / 01-01-2005 to 12-31-2005								
BAY FRONT	884	86,244	9,390	25.01%	0.37%	4.19%		3
MIDWEST ENERGY / 01-01-2005 to 12-31-2005								
BAY FRONT	1,800	112,621					*	4
UNION PACIFIC RAILROAD / 04-01-2005 to 12-31-2005								
BAY FRONT	1,205	36,346					*	5

COAL CONTRACT INFORMATION - SPECIFICATION AND COSTS

Coal Contract Information - Specification and Costs (Page E-25)

General footnotes

C.REISS, MIDWEST ENERGY AND UNION PACIFIC RAILROAD ARE TRANSPORTATION VENDORS ONLY.

ELECTRIC DISTRIBUTION LINES

1. If a utility has available the number of poles, but not miles of pole line, it will be considered satisfactory to determine miles of pole line by multiplying number of poles by average length of span, indicating in a footnote the average span used.
2. Urban distribution lines and rural distribution lines are to be reported separately for Wisconsin and for outside the state.
3. Urban distribution lines are defined as lines inside corporate limits of incorporated places, lines in urban areas adjacent to such corporate limits, and lines in unincorporated communities with urban characteristics. All pole lines used for urban distribution, including joint distribution and transmission, other joint distribution lines, and joint use of foreign lines are to be reported.

Description (a)	Miles of: Pole Line (b)	U.G. Conduit (subway) (c)	Buried Cable (d)	
Lines in Wisconsin				
Urban distribution lines - primary voltage	2,171	41	627	**1**
Urban distribution lines - secondary voltage				**2**
Rural distribution lines - primary voltage	5,941	1	581	**3**
Rural distribution lines - secondary voltage				**4**
Total in Wisconsin	**8,112**	**42**	**1,208**	
Lines outside the state				
Urban distribution lines - primary voltage	95		4	**5**
Urban distribution lines - secondary voltage				**6**
Rural distribution lines - primary voltage	347		39	**7**
Rural distribution lines - secondary voltage				**8**
Total outside the state	**442**	**0**	**43**	
Total lines of utility	**8,554**	**42**	**1,251**	

ELECTRIC DISTRIBUTION METERS & LINE TRANSFORMERS

Watt-hour demand distribution meters should be included below but external demand meters should not be included.

Particulars (a)	Number of Watt-Hour Meters (b)	Line Transformers		
		Number (c)	Total Cap. (kVA) (d)	
Number first of year	242,855	79,125	3,150	1
Acquired during year	11,473	1,647	96	2
Total	**254,328**	**80,772**	**3,246**	3
Retired during year	8,858	1,055	32	4
Sales, transfers or adjustments increase (decrease)				5
Number end of year	**245,470**	**79,717**	**3,214**	6
Number end of year accounted for as follows:				7
In customers' use	236,645	77,919	3,053	8
In utility's use	129			9
Inactive transformers on system				10
Locked meters on customers' premises	304			11
In stock	8,392	1,798	161	12
Total end of year	**245,470**	**79,717**	**3,214**	13

TRANSMISSION LINE STATISTICS

From (a)	To (b)	Operating Voltage (KV) (c)	Designed Voltage (KV) (d)	Type of Supporting Structure (e)	Length on Structure of Line Designated (f)	Length on Structures of Another Line (g)	Number of Circuits (h)	
ST CROIX RIVER	EAU CLAIRE	345.00	0.00	K-FRAME	61.06	0.00	1	1
		345.00	0.00		2.82	0.00	1	2
EAU CLAIRE	STEVENS POINT	345.00	0.00	K-FRAME	99.38	0.00	1	3
		345.00	0.00	TOWER	2.59	0.00	1	4
LA CROSSE	DPC TIE	161.00	0.00	H-FRAME	4.03	0.00	1	5
EAU CLAIRE	DPS TIE	161.00	0.00	H-FRAME	1.02	0.00	1	6
EAU CLAIRE	LA CROSSE	161.00	0.00	H-FRAME	80.28	0.00	1	7
TREMVAL	JACKSON COUNTY	161.00	0.00	H-FRAME	23.66	0.00	1	8
LA CROSSE	COULEE	161.00	0.00	H-FRAME	8.30	0.00	1	9
DPC	COULEE	161.00	0.00	H-FRAME	0.79	0.97	1	10
LA CROSSE	MONROE	161.00	0.00	H-FRAME	26.71	0.00	1	11
CRYSTAL CAVE	APPLE RIVER	161.00	0.00	1 POLE WD	38.97	1.04	1	12
EAU CLAIRE	ELK MOUND	161.00	0.00	H-FRAME	8.01	0.00	1	13
EAU CLAIRE	PRESTO	161.00	0.00	1POLE WD	3.28	0.00	1	14
EAU CLAIRE	CRYSTAL CAVE	161.00	0.00	H-FRAME	50.60	0.00	1	15
HYDRO LANE	LINE 3213	161.00	0.00	1 POLE WD	10.16	0.00	1	16
RED CEDAR	LINE 3213	161.00	0.00	1 POLE WD	1.52	0.00	2	17
STONE LAKE	MINONG	161.00	0.00	H-FRAME	20.38	0.00	1	18
STONE LAKE	GINGLES	161.00	0.00	1 POLE WD	63.31	0.00	1	19
		115.00	0.00	H-FRAME	383.54	11.92	1	20
		115.00	0.00	TOWER	52.97	0.00	1	21
		88.00	0.00	H-FRAME	72.78	0.00	1	22
		69.00	0.00	WOOD POLE	999.89	13.49	1	23
		69.00	0.00	TOWER	27.50	1.58	1	24
		34.50	0.00	1 POLE WD	363.68	2.83	1	25
		23.00	0.00	1 POLE WD	6.84	0.00	1	26
LA CROSSE	COULEE	69.00	0.00	UNDERGROUND	0.34	0.00	1	27
EXPENSES APPLICABLE TO		0.00	0.00		0.00	0.00	0	28
ALL LINES		0.00	0.00		0.00	0.00	0	29
				Total:	**2,414.41**	**31.83**	**28**	

TRANSMISSION LINE STATISTICS (cont.)

	Cost of Line			Expenses, Except Depreciation and Taxes				
Size of Conductor and Material (i)	Land (000's) (j)	Construction and Other Costs (000's) (k)	Total Cost (000's) (l)	Operation Expenses (000's) (m)	Maintenance Expenses (000's) (n)	Rents (000's) (o)	Total Expenses (000's) (p)	
795AS	398	5,239	**5,637**	0	0	0	**0**	**1**
795AS	0	0	**0**	0	0	0	**0**	**2**
795AS	355	6,440	**6,795**	0	0	0	**0**	**3**
795AS	0	0	**0**	0	0	0	**0**	**4**
795AS	25	593	**618**	0	0	0	**0**	**5**
477AS	0	26	**26**	0	0	0	**0**	**6**
477AS	420	2,358	**2,778**	0	0	0	**0**	**7**
795AS	159	941	**1,100**	0	0	0	**0**	**8**
477AS	96	370	**466**	0	0	0	**0**	**9**
636AS	0	83	**83**	0	0	0	**0**	**10**
705AS	174	1,305	**1,479**	0	0	0	**0**	**11**
954AS	276	3,792	**4,068**	0	0	0	**0**	**12**
795AS	13	564	**577**	0	0	0	**0**	**13**
4/0 AS	44	140	**184**	0	0	0	**0**	**14**
795AS	352	4,811	**5,163**	0	0	0	**0**	**15**
795AS	106	1,429	**1,535**	0	0	0	**0**	**16**
795AS	35	447	**482**	0	0	0	**0**	**17**
636AS	30	694	**724**	0	0	0	**0**	**18**
795AS	520	19,937	**20,457**	0	0	0	**0**	**19**
VARIOUS	2,313	41,800	**44,113**	0	0	0	**0**	**20**
VARIOUS	255	5,104	**5,359**	0	0	0	**0**	**21**
4/0 AS	136	2,624	**2,760**	0	0	0	**0**	**22**
VARIOUS	5,321	75,690	**81,011**	0	0	0	**0**	**23**
VARIOUS	100	1,930	**2,030**	0	0	0	**0**	**24**
VARIOUS	803	11,810	**12,613**	0	0	0	**0**	**25**
1250AL	8	501	**509**	0	0	0	**0**	**26**
	153	1,654	**1,807**	0	0	0	**0**	**27**
	0	0	**0**	(14,704)	1,751	290	**(12,663)**	**28**
	0	0	**0**	0	0	0	**0**	**29**
	12,092	**190,282**	**202,374**	**(14,704)**	**1,751**	**290**	**(12,663)**	

TRANSMISSION LINES ADDED DURING YEAR

From (a)	To (b)	Line Length (Miles) (c)	Supporting Structure: Type (d)	Supporting Structure: Average Number per Mile (e)	Circuits per Structure: Present (f)	Circuits per Structure: Ultimate (g)	
3499 DPC Tap	Whitehall Muni	0.00		0.00	0	0	1

TRANSMISSION LINES ADDED DURING YEAR (cont.)

Conductors				Line Cost					
Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	Land and Land Rights (000's) (l)	Poles, Towers and Fixtures (000's) (m)	Conductors and Devices (000's) (n)	Asset Retire. Costs (000's) (o)	Total (000's) (o)	
			0	0	21	7	0	**28**	**1**

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customershould not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Distribution U					
Under 10 MVa Capacity					
Bloomer	Distribution U	69.00	4.00	0.00	**1**
Cornell	Distribution U	115.00	2.40	0.00	**2**
Cornell	Distribution U	2.40	4.16	0.00	**3**
Hurley	Distribution U	115.00	12.50	0.00	**4**
Menomonie	Distribution U	69.00	4.16	0.00	**5**
Pokegama	Distribution U	69.00	13.80	0.00	**6**
U.S. Rubber	Distribution U	69.00	2.40	0.00	**7**
Viroqua	Distribution U	69.00	4.16	0.00	**8**
89 additional substations under 10 MVA	Distribution U				**9**
Total Distribution U Substations Under 10 MVa Capacity		**Count: 9**			
10 MVa or Above Capacity					
Bayfield	Distribution U	34.50	12.50	0.00	**10**
Arkansaw	Distribution U	69.00	23.90	0.00	**11**
Bangor	Distribution U	69.00	12.50	0.00	**12**
Blair	Distribution U	69.00	12.50	0.00	**13**
Bloomer	Distribution U	69.00	12.50	0.00	**14**
Cameron	Distribution U	69.00	12.50	0.00	**15**
Camp McCoy	Distribution U	69.00	6.90	0.00	**16**
Chippewa Falls	Distribution U	69.00	12.50	0.00	**17**
Coulee Ave	Distribution U	69.00	13.80	0.00	**18**
Coulee Ave	Distribution U	161.00	69.00	13.80	**19**
Doughty Road	Distribution U	69.00	23.90	0.00	**20**
Eagle Point	Distribution U	115.00	23.90	0.00	**21**
Ellis	Distribution U	69.00	12.50	0.00	**22**
Ellsworth Area	Distribution U	69.00	12.50	0.00	**23**
Galesville	Distribution U	69.00	12.50	0.00	**24**
Grassland	Distribution U	69.00	12.50	0.00	**25**
Griffin Street	Distribution U	69.00	12.50	0.00	**26**
Hallie	Distribution U	69.00	12.50	0.00	**27**
Hay River	Distribution U	69.00	23.90	0.00	**28**
Holmen Area	Distribution U	69.00	13.80	0.00	**29**

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
0	0	1		0	0	**1**
8	1	0		0	0	**2**
6	1	1		0	0	**3**
7	1	0		0	0	**4**
6	1	0	Capacitor Bank	1	5	**5**
7	1	0		0	0	**6**
9	3	0		0	0	**7**
5	1	0	Capacitor Bank	1	5	**8**
360	135	8	Capacitor Bank	9	47	**9**
408	**144**	**10**		**11**	**57**	
14	1	0		0	0	**10**
11	1	0		0	0	**11**
11	1	0		0	0	**12**
11	1	0		0	0	**13**
11	1	0		0	0	**14**
11	1	0	Capacitor Bank	1	5	**15**
11	1	1		0	0	**16**
44	2	0		0	0	**17**
93	2	0		0	0	**18**
182	2	0	Capacitor Bank	1	5	**19**
14	1	0		0	0	**20**
47	1	0		0	0	**21**
56	2	0		0	0	**22**
11	1	0		0	0	**23**
11	1	0		0	0	**24**
14	1	0		0	0	**25**
11	1	0		0	0	**26**
56	2	0		0	0	**27**
11	1	0		0	0	**28**
25	2	0	Capacitor Bank	1	5	**29**

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customershould not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Distribution U					
10 MVa or Above Capacity					
Hurley	Distribution U	115.00	13.80	0.00	**30**
Jeffers Road	Distribution U	161.00	23.90	0.00	**31**
Lake Camelia	Distribution U	69.00	23.00	0.00	**32**
London	Distribution U	69.00	12.50	0.00	**33**
Loyal	Distribution U	69.00	12.50	0.00	**34**
Madison Street	Distribution U	69.00	12.50	0.00	**35**
Mayfair	Distribution U	161.00	13.80	0.00	**36**
Menomonie	Distribution U	69.00	12.50	0.00	**37**
Naples	Distribution U	69.00	12.50	0.00	**38**
Neillsville	Distribution U	69.00	12.50	0.00	**39**
New Richmond	Distribution U	69.00	23.90	0.00	**40**
North Fork	Distribution U	34.50	12.50	0.00	**41**
Onalaska	Distribution U	69.00	13.80	0.00	**42**
Osceola	Distribution U	69.00	12.50	0.00	**43**
Otter Creek	Distribution U	69.00	12.50	0.00	**44**
Phillips	Distribution U	115.00	12.50	0.00	**45**
Prescott	Distribution U	69.00	12.50	0.00	**46**
Rice Lake	Distribution U	69.00	12.50	0.00	**47**
Rush River	Distribution U	69.00	23.00	0.00	**48**
Rusk	Distribution U	69.00	12.50	0.00	**49**
Second Street	Distribution U	34.50	13.80	0.00	**50**
Sheldon Pump	Distribution U	115.00	4.16	0.00	**51**
Sparta	Distribution U	69.00	12.50	0.00	**52**
Spencer	Distribution U	69.00	12.50	0.00	**53**
Stanley Area	Distribution U	69.00	23.90	0.00	**54**
Strum	Distribution U	69.00	12.50	0.00	**55**
Sumner	Distribution U	69.00	23.90	0.00	**56**
Swift Creek	Distribution U	69.00	13.80	0.00	**57**
Truax	Distribution U	69.00	12.50	0.00	**58**
Turtle Lake	Distribution U	69.00	12.50	0.00	**59**
U. S. Rubber	Distribution U	69.00	4.16	0.00	**60**
Viroqua	Distribution U	69.00	13.80	0.00	**61**

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
37	1	0		0	0	30
94	2	0		0	0	31
14	1	0		0	0	32
56	2	0		0	0	33
11	1	0		0	0	34
28	1	0		0	0	35
93	2	0		0	0	36
56	2	0		0	0	37
11	1	0		0	0	38
25	2	0	Capacitor Bank	1	5	39
14	1	0	Capacitor Bank	1	5	40
21	2	0		0	0	41
14	1	0	Capacitor Bank	1	5	42
25	2	0	Capacitor Bank	1	7	43
56	2	0		0	0	44
25	2	0		0	0	45
11	1	0		0	0	46
56	2	0	Capacitor Bank	1	5	47
30	2	0		0	0	48
11	1	0		0	0	49
14	1	0		0	0	50
14	1	0		0	0	51
56	2	0		0	0	52
25	2	0	Capacitor Bank	1	5	53
14	1	0		0	0	54
11	1	0	Capacitor Bank	1	5	55
14	1	0		0	0	56
56	2	0	Capacitor Bank	1	5	57
56	2	0		0	0	58
11	1	0		0	0	59
11	4	0		0	0	60
13	1	0		0	0	61

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customershould not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Distribution U					
10 MVa or Above Capacity					
Waumandee	Distribution U	69.00	23.90	0.00	**62**
West Salem	Distribution U	69.00	23.90	0.00	**63**
Willow River	Distribution U	115.00	23.00	0.00	**64**
Woodmour	Distribution U	69.00	23.00	0.00	**65**
Total Distribution U Substations 10 MVa or Above Capacity		**Count: 56**			
Total Distribution U Substations		**Count: 65**			
Substation Type: Transmission					
Under 10 MVa Capacity					
11 additional substations under 10 MVA	Transmission				**66**
Total Transmission Substations Under 10 MVa Capacity		**Count: 1**			
Total Transmission Substations		**Count: 1**			
Substation Type: Transmission A					
Under 10 MVa Capacity					
Cedar Falls	Transmission A	69.00	2.40	0.00	**67**
Jim Falls	Transmission A	12.50	7.20	0.00	**68**
Total Transmission A Substations Under 10 MVa Capacity		**Count: 2**			
10 MVa or Above Capacity					
Bay Front	Transmission A	88.00	34.50	0.00	**69**
Bay Front	Transmission A	88.00	13.80	0.00	**70**
Bay Front	Transmission A	34.50	13.80	0.00	**71**
Bay Front	Transmission A	88.00	13.80	0.00	**72**
Bay Front	Transmission A	88.00	69.00	0.00	**73**
Bay Front	Transmission A	115.00	88.00	0.00	**74**
Big Falls	Transmission A	69.00	2.40	0.00	**75**
Cedar Falls	Transmission A	69.00	23.90	0.00	**76**
Cornell Hydro	Transmission A	115.00	7.20	0.00	**77**
Eau Claire Dells	Transmission A	69.00	2.40	0.00	**78**
French Island	Transmission A	69.00	13.80	0.00	**79**
Holcombe	Transmission A	115.00	7.20	0.00	**80**

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
11	1	0		0	0	**62**
56	2	0	Capacitor Bank	1	5	**63**
98	2	0		0	0	**64**
11	1	0	Capacitor Bank	1	5	**65**
1814	**82**	**1**		**13**	**67**	
2222	**226**	**11**		**24**	**124**	
55	21	3	Capacitor Bank	1	5	**66**
55	**21**	**3**		**1**	**5**	
55	**21**	**3**		**1**	**5**	
7	1	0		0	0	**67**
1	3	0		0	0	**68**
8	**4**	**0**		**0**	**0**	
20	1	0		0	0	**69**
27	6	1		0	0	**70**
13	2	0	Capacitor Bank	2	12	**71**
52	2	0		0	0	**72**
20	1	0		0	0	**73**
50	1	0	Capacitor Bank	1	11	**74**
10	2	1		0	0	**75**
11	1	0		0	0	**76**
40	1	0		0	0	**77**
12	3	0		0	0	**78**
221	3	0	Capacitor Bank	1	5	**79**
38	3	0		0	0	**80**

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customershould not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Transmission A					
10 MVa or Above Capacity					
Jim Falls	Transmission A	115.00	69.00	0.00	**81**
Jim Falls	Transmission A	115.00	7.20	0.00	**82**
Jim Falls	Transmission A	69.00	12.50	0.00	**83**
St. Croix Falls	Transmission A	69.00	12.50	0.00	**84**
St. Croix Falls	Transmission A	12.50	2.40	0.00	**85**
Wheaton	Transmission A	161.00	13.80	0.00	**86**
Wissota	Transmission A	69.00	13.80	0.00	**87**
Total Transmission A Substations 10 MVa or Above Capacity		**Count: 19**			
Total Transmission A Substations		**Count: 21**			
Substation Type: Transmission U					
Under 10 MVa Capacity					
Ironwood (MI)	Transmission U	34.50	4.16	0.00	**88**
Total Transmission U Substations Under 10 MVa Capacity		**Count: 1**			
10 MVa or Above Capacity					
Chippewa Falls	Transmission U	69.00	4.00	0.00	**89**
Crystal Cave	Transmission U	161.00	115.00	13.80	**90**
Eau Claire	Transmission U	161.00	69.00	13.80	**91**
Eau Claire	Transmission U	345.00	161.00	13.80	**92**
Farmers Inn	Transmission U	69.00	12.50	0.00	**93**
Farmers Inn	Transmission U	161.00	69.00	0.00	**94**
Flambeau	Transmission U	34.50	13.80	0.00	**95**
Gingles	Transmission U	161.00	115.00	0.00	**96**
Gingles	Transmission U	115.00	69.00	0.00	**97**
Gingles	Transmission U	115.00	34.50	0.00	**98**
Hydro Lane	Transmission U	161.00	115.00	0.00	**99**
Hydro Lane	Transmission U	115.00	69.00	0.00	**100**
Hydro Lane	Transmission U	115.00	23.90	0.00	**101**
Hydro Lane	Transmission U	115.00	12.50	0.00	**102**
Jackson County	Transmission U	161.00	69.00	13.50	**103**
La Crosse	Transmission U	161.00	69.00	13.80	**104**

SUBSTATIONS (cont.)

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Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
112	1	0		0	0	**81**
67	2	0		0	0	**82**
11	1	0		0	0	**83**
28	1	0		0	0	**84**
29	5	1		0	0	**85**
435	3	0		0	0	**86**
50	6	1		0	0	**87**
1246	**45**	**4**		**4**	**28**	
1254	**49**	**4**		**4**	**28**	
6	4	1		0	0	**88**
6	**4**	**1**		**0**	**0**	
46	2	0		0	0	**89**
187	1	0		0	0	**90**
224	2	0	Capacitor Bank	4	356	**91**
600	2	0		0	0	**92**
14	1	0	Capacitor Bank	1	5	**93**
50	1	0		0	0	**94**
20	1	0		0	0	**95**
187	1	0		0	0	**96**
42	1	0		0	0	**97**
94	2	0	Capacitor Bank	2	12	**98**
187	1	0		0	0	**99**
42	1	0		0	0	**100**
47	1	0		0	0	**101**
28	1	0		0	0	**102**
46	1	0		0	0	**103**
140	2	0		0	0	**104**

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customershould not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Transmission U					
10 MVa or Above Capacity					
La Crosse	Transmission U	69.00	13.80	0.00	**105**
Marshland	Transmission U	161.00	69.00	13.80	**106**
Monroe County	Transmission U	161.00	69.00	0.00	**107**
Osprey	Transmission U	69.00	23.90	0.00	**108**
Osprey	Transmission U	115.00	69.00	0.00	**109**
Park Falls 115KV	Transmission U	115.00	34.50	0.00	**110**
Pine Lake	Transmission U	115.00	69.00	0.00	**111**
Pine Lake	Transmission U	161.00	115.00	0.00	**112**
Prentice	Transmission U	115.00	69.00	0.00	**113**
Prentice	Transmission U	115.00	12.50	0.00	**114**
Red Cedar	Transmission U	161.00	69.00	0.00	**115**
Red Cedar	Transmission U	69.00	12.50	0.00	**116**
River Falls	Transmission U	115.00	69.00	0.00	**117**
Seven Mile	Transmission U	161.00	69.00	13.80	**118**
Stone Lake	Transmission U	161.00	69.00	0.00	**119**
T-Corners	Transmission U	115.00	69.00	13.80	**120**
T-Corners	Transmission U	69.00	23.90	0.00	**121**
Trails End	Transmission U	69.00	23.90	0.00	**122**
Tremval	Transmission U	161.00	69.00	13.80	**123**
Whitetail	Transmission U	69.00	34.50	7.20	**124**
Whitetail	Transmission U	69.00	13.80	0.00	**125**
Ironwood (MI)	Transmission U	115.00	34.50	0.00	**126**
Ironwood (MI)	Transmission U	88.00	34.50	0.00	**127**
Total Transmission U Substations 10 MVa or Above Capacity		**Count: 39**			
Total Transmission U Substations		**Count: 40**			

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
93	2	0	Capacitor Bank	1	5	**105**
224	2	0		0	0	**106**
70	1	0	Capacitor Bank	1	14	**107**
11	1	0		0	0	**108**
47	1	0		0	0	**109**
56	2	0	Capacitor Bank	1	6	**110**
224	2	0		0	0	**111**
112	1	1		0	0	**112**
50	1	0		0	0	**113**
11	1	0	Capacitor Bank	1	13	**114**
70	1	0		0	0	**115**
56	2	0		0	0	**116**
70	1	0	Capacitor Bank	1	5	**117**
112	1	0		0	0	**118**
70	1	0	Capacitor Bank	3	47	**119**
182	2	0	Capacitor Bank	5	140	**120**
56	2	0	Capacitor Bank	1	5	**121**
11	1	0		0	0	**122**
70	1	1		0	0	**123**
20	1	1	Capacitor Bank	1	5	**124**
11	1	0		0	0	**125**
100	2	0	Capacitor Bank	1	11	**126**
25	1	0		0	0	**127**
3705	**52**	**3**		**23**	**624**	
3711	**56**	**4**		**23**	**624**	

TRANSMISSION OF ELECTRICITY FOR OTHERS

1. Report all transmision of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the year.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column(a) the company or public authority that paid for the transmission service. Report in column(b) the company or public authority that the energy was received from and in column(c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractural terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See FERC General Instruction for definition of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number. Use footnotes to list additional FERC Rate Schedules or contract designations under which service, as identified in column (d), is provided.

Payment By (Company of Public Authority) (a)	Energy Received From (Company of Public Authority) (b)	Energy Delivered To (Company of Public Authority) (c)	Statistical Classifi-cation (d)	FERC Rate Schedule of Tariff Number (e)		
Wisconsin Power & Light Company			OS	NSPW 473	*	1

TRANSMISSION OF ELECTRICITY FOR OTHERS (cont.)

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation of the substation, or other apropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (li) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes on the Electric Energy Account schedule, lines 12 and 13, respectively.
11. Footnote entries and provide explanations following all required data.

Point of Receipt/ Point of Delivery (Substation or Other Designation (f), (g)	Billing Demand (MW) (h)	Transfer of Energy		Revenue from Transmission of Electricity for Others				
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (000's) (k)	Energy Charges (000's) (l)	Other Charges (000's) (m)	Total Revenues (000's) (n)	
	0	0	0	0	0	418	**418**	*** 1**

TRANSMISSION OF ELECTRICITY FOR OTHERS

Transmission of Electricity for Others (Page E-34)

General footnotes

Line charge for Rocky Run - Arpin 345 kV Line. This agreement was terminated in 2005.

TRANSMISSION OF ELECTRICITY FOR OTHERS (cont.)

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TRANSMISSION OF ELECTRICITY BY OTHERS

1. Report all transmision of electricity, i.e., wheeling, provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the year.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use footnotes as necessary to report all companies or public authorities that provided transmission service for the year.
3. In column (a) enter a Statistical Classification code based on the original contractural terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Point to Point Transmission Reservation, NF - non-firm transmission service, and OS - Other Transmission Service. See FERC General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. In column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Footnote entries and provide explanations following all required data.

		Transfer of Energy		Expenses for Transmission of Electricity by Others				
Name of Company or Public Authority (Footnote Affiliation) (a)	**Statistical Classifi-cation (b)**	**Megawatt-Hours Received (c)**	**Megawatt-Hours Delivered (d)**	**Demand Charges (000's) (e)**	**Energy Charges (000's) (f)**	**Other Charges (000's) (g)**	**Total Cost of Transmission (000's) (h)**	
NONE								1
	Total:	**0**	**0**	**0**	**0**	**0**	**0**	

POWER COST ADJUSTMENT CLAUSE

Report below the revenue derived from the power cost adjustment clause for the year for each rate schedule that is reported on page E-8. Do not combine any of the rate schedules.

Rate Schedules (a)	PCAC Revenues (Wisconsin only) (000's) (b)	
Account 440		
Rg-1 Residential	7,914	**1**
Rg-3 Residential Managed	1	**2**
Fg-1 Farm	425	**3**
Cg-6 Optional Off Peak	2	**4**
S-1 Automatic Protective	8	**5**
Total Account 440:	**8,350**	
Account 441		
NONE		**6**
Total Account 441:	**0**	
Account 442		
Cg-1 Sm General TOD	20	**7**
Cg-2 Sm General	1,613	**8**
Cg-5 General	4,544	**9**
Cg-6 Opt Off Peak	14	**10**
Cp-2 Peak Controlled General	124	**11**
Cg-9 Lg General TOD	8,359	**12**
Cp-1 Peak Controlled TOD	3,230	**13**
Rtp-1 Power Supply Requirement	573	**14**
Rtp-1 Bundled Requirements	45	**15**
S-1 Experimental RTP	16	**16**
Total Account 442:	**18,538**	
Account 444		
Ms-2 Co. Owned Street Lighting	57	**17**
Ms-4 Cust. Owned Street Lighting	35	**18**
Ms-6 UG Area Lighting	4	**19**
Ms-7 Metered Street Lighting	2	**20**
Total Account 444:	**98**	
Account 445		
Mp-1 Muni. Water Pumping	53	**21**
Total Account 445:	**53**	
Total:	**27,039**	

POWER COST ADJUSTMENT CLAUSE FACTOR

1. Report below in col. (b) the monthly PCAC Factors actually applied in determining monthly revenues for the year.
2. The monthly PCAC Factor may be stated as dollars per Kwh according to your power cost adjustment clause.

Month (a)	Adjustment Factor (Wisconsin only) (b)		
January	0.003180		1
February	0.003180		2
March	0.003180		3
April	0.003180		4
May	0.004900	*	5
June	0.004900		6
July	0.004900		7
August	0.004900		8
September	0.004900		9
October	0.005150	*	10
November	0.006640	*	11
December	0.006640		12

POWER COST ADJUSTMENT CLAUSE FACTOR

Power Cost Adjustment Clause Factor (Page E-38)

General footnotes

5. New Power Clause Adjustment Factor went into effect May 19, 2005.

10. New Power Clause Adjustment Factor went into effect October 1, 2005.

11. New Power Clause Adjustment Factor went into effect November 11, 2005.

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Ashland County	
Cities	
ASHLAND	4,343
MELLEN	495
Total Cities:	**4,838**
Villages	
BUTTERNUT	263
Total Villages:	**263**
Towns	
AGENDA	89
ASHLAND	110
CHIPPEWA	113
GINGLES	251
GORDON	18
JACOBS	365
LA POINTE	822
MARENGO	62
MORSE	86
PEEKSVILLE	27
SANBORN	135
SHANAGOLDEN	1
WHITE RIVER	208
Total Towns:	**2,287**
Total Ashland County:	**7,388**
Barron County	
Cities	
BARRON	14
CHETEK	1,256
RICE LAKE	12
Total Cities:	**1,282**
Villages	
ALMENA	383
CAMERON	856
DALLAS	198
HAUGEN	181
NEW AUBURN	8
PRAIRIE FARM	246
TURTLE LAKE	574
Total Villages:	**2,446**
Towns	
ALMENA	247
ARLAND	113
BARRON	62
BEAR LAKE	20

Barron County (a)	Customers End of Year (b)
Towns	
CEDAR LAKE	1,063
CHETEK	334
CLINTON	205
CRYSTAL LAKE	99
CUMBERLAND	42
DALLAS	122
DOVRE	58
DOYLE	182
LAKELAND	66
MAPLE GROVE	159
MAPLE PLAIN	45
OAK GROVE	193
PRAIRIE FARM	141
PRAIRIE LAKE	83
RICE LAKE	551
SIOUX CREEK	66
STANFOLD	39
STANLEY	239
SUMNER	45
TURTLE LAKE	127
VANCE CREEK	139
Total Towns:	**4,440**
Total Barron County:	**8,168**
Bayfield County	
Cities	
BAYFIELD	719
WASHBURN	1,161
Total Cities:	**1,880**
Villages	
MASON	55
Total Villages:	**55**
Towns	
BARKSDALE	220
BAYFIELD	445
BAYVIEW	146
BELL	138
CABLE	532
CLOVER	125
DRUMMOND	247
EILEEN	116
GRAND VIEW	102
IRON RIVER	2
KELLY	86
KEYSTONE	10

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Bayfield County	
Towns	
LINCOLN	78
MASON	36
NAMEKAGON	219
ORIENTA	40
OULU	74
PORT WING	278
RUSSELL	380
TRIPP	14
WASHBURN	55
Total Towns:	**3,343**
Total Bayfield County:	**5,278**
Buffalo County	
Cities	
ALMA	546
BUFFALO CITY	53
FOUNTAIN CITY	534
MONDOVI	1,440
Total Cities:	**2,573**
Villages	
COCHRANE	302
NELSON	243
Total Villages:	**545**
Towns	
ALMA	4
BELVIDERE	53
BUFFALO	212
CANTON	44
GLENCOE	3
LINCOLN	43
MONDOVI	3
MONTANA	17
NAPLES	79
NELSON	3
WAUMANDEE	172
Total Towns:	**633**
Total Buffalo County:	**3,751**
Chippewa County	
Cities	
BLOOMER	6
CHIPPEWA FALLS	6,732
CORNELL	1

Chippewa County (a)	Customers End of Year (b)
Cities	
EAU CLAIRE	917
STANLEY	1,092
Total Cities:	**8,748**
Villages	
BOYD	315
CADOTT	3
LAKE HALLIE	30
NEW AUBURN	239
Total Villages:	**587**
Towns	
ANSON	765
AUBURN	82
BLOOMER	66
COOKS VALLEY	125
DELMAR	117
EAGLE POINT	845
EDSON	135
GOETZ	3
HALLIE	2,349
HOWARD	32
LAFAYETTE	2,463
RUBY	13
SIGEL	79
TILDEN	470
WHEATON	244
WOODMOHR	109
Total Towns:	**7,897**
Total Chippewa County:	**17,232**
Clark County	
Cities	
ABBOTSFORD	809
COLBY	564
GREENWOOD	598
LOYAL	703
NEILLSVILLE	1,441
OWEN	558
THORP	934
Total Cities:	**5,607**
Villages	
CURTISS	110
DORCHESTER	457
GRANTON	221
UNITY	94

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Clark County	
Villages	
WITHEE	274
Total Villages:	**1,156**
Towns	
BEAVER	19
COLBY	110
EATON	128
FOSTER	12
FREMONT	203
GRANT	143
GREEN GROVE	20
HIXON	50
HOARD	44
LONGWOOD	26
LOYAL	127
LYNN	76
MAYVILLE	80
MENTOR	142
PINE VALLEY	172
RESEBURG	55
SHERMAN	67
THORP	77
UNITY	171
WARNER	7
WESTON	121
WITHEE	194
WORDEN	29
YORK	126
Total Towns:	**2,199**
Total Clark County:	**8,962**
Crawford County	
Villages	
DE SOTO	56
Total Villages:	**56**
Towns	
FREEMAN	11
Total Towns:	**11**
Total Crawford County:	**67**
Dunn County	
Cities	
MENOMONIE	6,673
Total Cities:	**6,673**

Location (a)	Customers End of Year (b)
Dunn County	
Villages	
BOYCEVILLE	531
COLFAX	619
DOWNING	105
ELK MOUND	346
KNAPP	240
RIDGELAND	201
WHEELER	176
Total Villages:	**2,218**
Towns	
COLFAX	29
DUNN	171
EAU GALLE	224
ELK MOUND	96
HAY RIVER	1
LUCAS	56
MENOMONIE	800
NEW HAVEN	9
OTTER CREEK	1
RED CEDAR	516
SAND CREEK	157
SHERIDAN	35
SHERMAN	77
SPRINGBROOK	258
STANTON	51
TAINTER	320
TIFFANY	100
WESTON	65
WILSON	56
Total Towns:	**3,022**
Total Dunn County:	**11,913**
Eau Claire County	
Cities	
ALTOONA	2,299
AUGUSTA	794
EAU CLAIRE	28,290
Total Cities:	**31,383**
Villages	
FAIRCHILD	302
FALL CREEK	630
Total Villages:	**932**
Towns	
BRIDGE CREEK	46

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Eau Claire County	
Towns	
BRUNSWICK	96
CLEAR CREEK	54
DRAMMEN	4
FAIRCHILD	36
LINCOLN	56
OTTER CREEK	66
SEYMOUR	366
UNION	969
WASHINGTON	1,473
Total Towns:	**3,166**
Total Eau Claire County:	**35,481**
Iron County	
Cities	
HURLEY	1,138
MONTREAL	537
Total Cities:	**1,675**
Towns	
ANDERSON	49
CAREY	68
GURNEY	52
KIMBALL	267
KNIGHT	139
MERCER	1,735
OMA	135
PENCE	121
SAXON	150
SHERMAN	25
Total Towns:	**2,741**
Total Iron County:	**4,416**
Jackson County	
Villages	
ALMA CENTER	263
HIXTON	261
MELROSE	297
TAYLOR	256
Total Villages:	**1,077**
Towns	
ADAMS	76
ALMA	95
CLEVELAND	18
CURRAN	27

Jackson County (a)	Customers End of Year (b)
Towns	
GARDEN VALLEY	66
HIXTON	64
MELROSE	65
NORTH BEND	94
NORTHFIELD	102
SPRINGFIELD	78
Total Towns:	**685**
Total Jackson County:	**1,762**
La Crosse County	
Cities	
LA CROSSE	24,413
ONALASKA	5,999
Total Cities:	**30,412**
Villages	
HOLMEN	2,378
ROCKLAND	252
WEST SALEM	2,134
Total Villages:	**4,764**
Towns	
BANGOR	65
BARRE	489
BURNS	140
CAMPBELL	2,082
FARMINGTON	400
GREENFIELD	401
HAMILTON	905
HOLLAND	68
MEDARY	553
ONALASKA	646
SHELBY	1,388
WASHINGTON	46
Total Towns:	**7,183**
Total La Crosse County:	**42,359**
Lincoln County	
Towns	
SOMO	39
Total Towns:	**39**
Total Lincoln County:	**39**
Marathon County	
Cities	
ABBOTSFORD	294

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Marathon County	
Cities	
COLBY	267
Total Cities:	**561**
Villages	
ATHENS	575
SPENCER	919
UNITY	110
Total Villages:	**1,604**
Towns	
BERN	27
BRIGHTON	22
FRANKFORT	216
HALSEY	34
HOLTON	13
HULL	150
JOHNSON	356
RIETBROCK	75
SPENCER	36
WIEN	115
Total Towns:	**1,044**
Total Marathon County:	**3,209**
Monroe County	
Cities	
SPARTA	4,427
Total Cities:	**4,427**
Villages	
CASHTON	2
MELVINA	55
NORWALK	289
Total Villages:	**346**
Towns	
ANGELO	326
GREENFIELD	1
JEFFERSON	110
LA FAYETTE	117
LEON	108
LITTLE FALLS	424
NEW LYME	52
PORTLAND	61
RIDGEVILLE	35
SHELDON	2
SPARTA	1,145

Location (a)	Customers End of Year (b)
Monroe County	
Towns	
WELLS	33
Total Towns:	**2,414**
Total Monroe County:	**7,187**
Oneida County	
Towns	
LYNNE	53
Total Towns:	**53**
Total Oneida County:	**53**
Pepin County	
Cities	
DURAND	964
Total Cities:	**964**
Villages	
PEPIN	577
STOCKHOLM	109
Total Villages:	**686**
Towns	
DURAND	200
LIMA	87
PEPIN	294
STOCKHOLM	26
WATERVILLE	335
WAUBEEK	95
Total Towns:	**1,037**
Total Pepin County:	**2,687**
Pierce County	
Cities	
PRESCOTT	1,991
Total Cities:	**1,991**
Villages	
BAY CITY	276
ELLSWORTH	1,345
ELMWOOD	452
MAIDEN ROCK	108
PLUM CITY	304
SPRING VALLEY	533
Total Villages:	**3,018**
Towns	
CLIFTON	285
EL PASO	5

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Pierce County	
Towns	
ELLSWORTH	38
GILMAN	126
HARTLAND	32
ISABELLE	116
MAIDEN ROCK	53
OAK GROVE	54
RIVER FALLS	34
ROCK ELM	185
SALEM	21
SPRING LAKE	149
TRENTON	437
TRIMBELLE	14
UNION	182
Total Towns:	**1,731**
Total Pierce County:	**6,740**
Polk County	
Cities	
AMERY	1,568
SAINT CROIX FALLS	1,149
Total Cities:	**2,717**
Villages	
CLAYTON	249
CLEAR LAKE	549
DRESSER	427
LUCK	625
OSCEOLA	1,211
TURTLE LAKE	34
Total Villages:	**3,095**
Towns	
ALDEN	338
APPLE RIVER	35
BEAVER	34
BLACK BROOK	157
BONE LAKE	129
CLAYTON	391
CLEAR LAKE	275
FARMINGTON	207
GARFIELD	293
JOHNSTOWN	3
LINCOLN	619
LUCK	172
MCKINLEY	92

Polk County Towns (a)	Customers End of Year (b)
OSCEOLA	529
SAINT CROIX FALLS	83
Total Towns:	**3,357**
Total Polk County:	**9,169**
Price County	
Cities	
PARK FALLS	1,530
PHILLIPS	1,082
Total Cities:	**2,612**
Villages	
CATAWBA	82
KENNAN	92
PRENTICE	388
Total Villages:	**562**
Towns	
CATAWBA	3
EISENSTEIN	106
ELK	329
EMERY	29
FIFIELD	171
FLAMBEAU	55
GEORGETOWN	64
HACKETT	9
HARMONY	71
HILL	2
KENNAN	19
KNOX	131
LAKE	504
OGEMA	167
PRENTICE	124
WORCESTER	284
Total Towns:	**2,068**
Total Price County:	**5,242**
Rusk County	
Cities	
LADYSMITH	1,869
Total Cities:	**1,869**
Villages	
BRUCE	479
CONRATH	54
GLEN FLORA	70
HAWKINS	219
INGRAM	54

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Rusk County	
Villages	
SHELDON	176
TONY	85
WEYERHAEUSER	183
Total Villages:	**1,320**
Towns	
ATLANTA	115
BIG BEND	33
BIG FALLS	24
DEWEY	200
FLAMBEAU	265
GRANT	345
GROW	110
HAWKINS	7
LAWRENCE	13
MARSHALL	119
RICHLAND	6
STRICKLAND	10
STUBBS	302
THORNAPPLE	80
TRUE	67
WILSON	3
Total Towns:	**1,699**
Total Rusk County:	**4,888**
Saint Croix County	
Cities	
GLENWOOD CITY	640
HUDSON	6,351
NEW RICHMOND	86
Total Cities:	**7,077**
Villages	
BALDWIN	1,576
DEER PARK	147
HAMMOND	656
NORTH HUDSON	1,532
ROBERTS	725
SOMERSET	844
STAR PRAIRIE	276
WILSON	93
WOODVILLE	605
Total Villages:	**6,454**
Towns	
BALDWIN	306

Saint Croix County (a)	Customers End of Year (b)
Towns	
CADY	82
CYLON	65
EAU GALLE	55
EMERALD	84
FOREST	128
GLENWOOD	143
HAMMOND	544
HUDSON	1,625
KINNICKINNIC	150
RICHMOND	218
RUSH RIVER	38
SAINT JOSEPH	594
SOMERSET	683
SPRINGFIELD	158
STANTON	140
STAR PRAIRIE	1,286
TROY	386
WARREN	141
Total Towns:	**6,826**
Total Saint Croix County:	**20,357**
Sawyer County	
Cities	
HAYWARD	1,688
Total Cities:	**1,688**
Towns	
BASS LAKE	1,227
COUDERAY	75
EDGEWATER	78
HAYWARD	1,215
LENROOT	1,005
ROUND LAKE	43
SAND LAKE	1,224
Total Towns:	**4,867**
Total Sawyer County:	**6,555**
Taylor County	
Cities	
MEDFORD	1
Total Cities:	**1**
Villages	
GILMAN	255
LUBLIN	97
RIB LAKE	466

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Taylor County	
Villages	
STETSONVILLE	281
Total Villages:	**1,099**
Towns	
CHELSEA	73
FORD	26
GREENWOOD	40
LITTLE BLACK	118
RIB LAKE	105
ROOSEVELT	64
TAFT	27
WESTBORO	220
Total Towns:	**673**
Total Taylor County:	**1,773**
Trempealeau County	
Cities	
BLAIR	701
GALESVILLE	795
INDEPENDENCE	739
OSSEO	924
WHITEHALL	2
Total Cities:	**3,161**
Villages	
ELEVA	348
ETTRICK	261
PIGEON FALLS	223
STRUM	486
TREMPEALEAU	1
Total Villages:	**1,319**
Towns	
ALBION	121
BURNSIDE	37
CALEDONIA	21
DODGE	158
ETTRICK	36
GALE	167
HALE	3
LINCOLN	155
PIGEON	139
PRESTON	89
SUMNER	19
TREMPEALEAU	156

Location (a)	Customers End of Year (b)
Trempealeau County	
Towns	
UNITY	26
Total Towns:	**1,127**
Total Trempealeau County:	**5,607**
Vernon County	
Cities	
VIROQUA	2,220
Total Cities:	**2,220**
Villages	
CHASEBURG	170
COON VALLEY	404
DE SOTO	171
GENOA	146
STODDARD	418
Total Villages:	**1,309**
Towns	
BERGEN	249
CHRISTIANA	46
COON	247
GENOA	45
HAMBURG	119
HARMONY	91
JEFFERSON	129
STERLING	4
VIROQUA	254
WHEATLAND	10
Total Towns:	**1,194**
Total Vernon County:	**4,723**
Vilas County	
Towns	
BOULDER JUNCTION	159
MANITOWISH WATERS	1,371
PRESQUE ISLE	1,097
WINCHESTER	639
Total Towns:	**3,266**
Total Vilas County:	**3,266**
Washburn County	
Cities	
SHELL LAKE	910
Total Cities:	**910**

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Washburn County	
Villages	
BIRCHWOOD	348
Total Villages:	**348**
Towns	
BARRONETT	12
BASHAW	27
BEAVER BROOK	70
BIRCHWOOD	339
LONG LAKE	221
SARONA	51
SPRINGBROOK	143
STINNETT	11
STONE LAKE	158
TREGO	199
Total Towns:	**1,231**
Total Washburn County:	**2,489**
Total Company:	**230,761**

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Electric Customers Served (Page E-39)

General footnotes

Following is a list of customers that are not identified by city, village or town due to a billing system conversion during 2005.

County	Customers
Ashland	47
Barron	96
Bayfield	93
Buffalo	18
Burnett	1
Chippewa	136
Clark	43
Dunn	39
Eau Claire	45
Iron	52
Jackson	15
La Crosse	107
Marathon	31
Monroe	83
Pepin	23
Pierce	85
Polk	139
Price	32
Rusk	37
Sawyer	138
St. Croix	428
Taylor	13
Trempealeau	34
Vernon	40
Vilas	89
Washburn	65
Total	1,929

Total Electric Customers Identified by City, Village or Town	230,761
Electric Customers Not Identified by City, Village or Town	1,929
Total Electric Customers	232,690

GAS OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (000's) (b)	Last Year (000's) (c)	
Operating Revenues			
Sales of Gas			
Sales of Gas (480-484)	156,729	136,727	**1**
Total Sales of Gas	**156,729**	**136,727**	
Other Operating Revenues			
Forfeited Discounts (487)	307	243	**2**
Miscellaneous Service Revenues (488)	179	164	**3**
Transportation (489)	1,380	1,572	**4**
Rent from Property (493)	0		**5**
Other Gas Revenues (495)	10	11	**6**
Penalty Revenue (497)	0		**7**
Utility Revenue Incentive (PBR) (498)	0		**8**
Total Other Operating Revenues	**1,876**	**1,990**	
Total Operating Revenues	**158,605**	**138,717**	
Production Expenses			
Manufactured Gas Production Expenses (700-742)	1,063	875	**9**
Purchased Gas Expenses (804-813)	128,176	108,567	**10**
Total Production Expenses	**129,239**	**109,442**	
Operation and Maintenance Expenses			
Storage Expenses (840-848.3)	176	241	**11**
Transmission Expenses (850-867)	0		**12**
Distribution Expenses (870-894)	4,807	4,437	**13**
Customer Accounts Expenses (901-905)	3,574	3,311	**14**
Customer Service Expenses (907-910)	1,206	1,276	**15**
Sales Promotion Expenses (911-916)	136	93	**16**
Administrative and General Expenses (920-935)	4,169	4,861	**17**
Total Operation and Maintenance Expenses	**14,068**	**14,219**	
Other Operating Expenses			
Depreciation Expense (403)	5,990	5,716	**18**
Amortization Limited-Term Utility Investment (404)	602	269	**19**
Amortization of Other Utility Plant (405)	46	48	**20**
Amortization of Utility Plant Acquisition Adjustment (406)	0		**21**
Amortization of Property Losses (407.1)	0		**22**
Amortization of Conversion Expenses (407.2)	0		**23**
Regulatory Debits (407.3)	0		**24**
(Less) Regulatory Credits (407.4)	0		**25**
Taxes Other Than Income Taxes (408.1)	1,916	1,850	**26**
Income Taxes (409.1)	(174)	70	**27**
Provision for Deferred Income Taxes (410.1, 411.1)	1,698	1,851	**28**

GAS OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (000's) (b)	Last Year (000's) (c)	
Other Operating Expenses			
Investment Tax Credit Adjustment (411.4)	(53)	(54)	**29**
Total Other Operating Expenses	**10,025**	**9,750**	
Total Operating Expenses	**153,332**	**133,411**	
NET OPERATING INCOME	**5,273**	**5,306**	

GAS EXPENSES

Report all amounts on the basis and in conformity with the uniform system of accounts and accounting directives prescribed by this commission. Allocate "Total Operations" amounts jurisdictionally between Wisconsin (PSCW) jurisdiction and all other jurisdiction.

Particulars (a)	Wisconsin Jurisdictional Operations Labor (000's) (b)	Wisconsin Jurisdictional Operations Other (000's) (c)	Other Jurisdictional Operations Labor (000's) (d)	Other Jurisdictional Operations Other (000's) (e)	Total Operations (000's) (f)	
Production Expenses						
Manufactured Gas Production Expenses (700-742)		1,060		3	1,063	**1**
Purchased Gas Expenses (804-813)	69	119,858	4	8,245	128,176	**2**
Total Production Expenses	**69**	**120,918**	**4**	**8,248**	**129,239**	
Operation and Maintenance Expenses						
Storage Expenses (840-848.3)	117	47	9	3	176	**3**
Transmission Expenses (850-867)					0	**4**
Distribution Expenses (870-894)	2,808	1,790	125	84	4,807	**5**
Customer Accounts Expenses (901-905)	1,342	2,035	77	120	3,574	**6**
Customer Service Expenses (907-910)	261	920	15	10	1,206	**7**
Sales Promotion Expenses (911-916)	48	80	3	5	136	**8**
Administrative and General Expenses (920-935)	2,129	1,843	106	91	4,169	**9**
Total Operation and Maintenance Expenses	**6,705**	**6,715**	**335**	**313**	**14,068**	
Other Operating Expenses						
Depreciation Expense (403)		5,721		269	5,990	**10**
Amortization Limited-Term Utility Investment (404)		575		27	602	**11**
Amortization of Other Utility Plant (405)		44		2	46	**12**
Amortization of Utility Plant Acquisition Adjustment (406)					0	**13**
Amortization of Property Losses (407.1)					0	**14**
Amortization of Conversion Expenses (407.2)					0	**15**
Regulatory Debits (407.3)					0	**16**
(Less) Regulatory Credits (407.4)					0	**17**
Taxes Other Than Income Taxes (408.1)		1,847		69	1,916	**18**
Income Taxes (409.1)		(414)		240	(174)	**19**
Provision for Deferred Income Taxes (410.1, 411.1)		1,689		9	1,698	**20**
Investment Tax Credit Adjustment (411.4)		(51)		(2)	(53)	**21**
Total Other Operating Expenses	**0**	**9,411**	**0**	**614**	**10,025**	
Total Operating Expenses	**6,774**	**137,044**	**339**	**9,175**	**153,332**	

SALES OF GAS BY RATE SCHEDULE

1. Report data by rate schedule (including unbilled revenues and therms), classified between space heating and non-space heating customers and show totals for each account 480-484 incl.
2. Report average number of customers on basis of number of meters. Where meters are added for billing purposes, count one customer for each group of meters so added.
3. Compute averages on basis of 12 month end figures.
4. For industrial interruptible sales, report data by priority of interruption if not provided for by separate rate schedules.

Particulars (a)	Rate Schedule (b)	Average Number Customers (c)	Therms Sold (d)	Amount (000's) (e)		
Residential Sales (480)						
Residential	201,231	81,772	60,104,010	71,242	*	1
	301	4,655	4,738,320	5,318	*	2
	299	1		3	*	3
Total Account 480:		**86,428**	**64,842,330**	**76,563**		
Commercial and Industrial Sales (481)						
Commercial	202,222,232	10,523	49,535,280	52,196	*	4
	302,304	620	2,827,330	3,056	*	5
Industrial	203,204	1	579,580	505	*	6
	304	1	1,365,710	1,027	*	7
Large Volume Interruptible	206,207	23	14,587,650	5,019		8
	303	1	51,500	15		9
Small Volume Interruptible	206,207	236	10,518,640	16,130		10
	303	5	302,660	272		11
Total Account 481:		**11,410**	**79,768,350**	**78,220**		
Sales for Resale (483)						
	NONE					12
Total Account 483:		**0**	**0**	**0**		
Interdepartmental Sales (484)						
Firm Michigan	NONE	1	5,600	3		13
Firm Wisconsin	NONE	5	178,151	178		14
Interruptible Wisconsin	NONE	2	2,777,934	1,765		15
Other Wisconsin	NONE					16
Total Account 484:		**8**	**2,961,685**	**1,946**		
	Total Sales of Gas	**97,846**	**147,572,365**	**156,729**		
Transportation (489)						
C&I Firm	212,214	4	15,293,900	345		17
C&I Interdepartmental Interruptible	NONE	1	7,492,785	66		18
C&I Interruptible	217	15	28,744,490	969		19
Total Account 489:		**20**	**51,531,175**	**1,380**		
	Total Throughput	**97,866**	**199,103,540**	**158,109**		

SALES OF GAS BY RATE SCHEDULE

Sales of Gas by Rate Schedule (Page G-03)

General footnotes

Due to a billing system conversion in 2005, we no longer break out space and non-space heating customers.

OTHER OPERATING REVENUES (GAS)

1. Report succinct statement of the revenues in each account and show separate totals for each account.
2. Report name of lessee and description of property for major items of rent revenue. Group other rents less than $25,000 by classes.
3. For sales of water and water power, report name of purchaser, purpose for which water used and the development supplying water.
4. Report basis of charges for any interdepartmental rents.
5. Report details of major items in Acct. 456. Group items less than $25,000.

Particulars (a)	Amount (000's) (b)	
Forfeited Discounts (487):		
LATE PAYMENT FEES	307	1
Total Forfeited Discounts (487)	**307**	
Miscellaneous Service Revenues (488):		
SERVICE CONNECTIONS	171	2
RETURNED CHECK CHARGE	8	3
Total Miscellaneous Service Revenues (488)	**179**	
Revenues from Transportation of Gas of Others (489):		
C&I FIRM	345	4
C&I INTERRUPTIBLE	969	5
C&I INTERDEPARTMENTAL INTERRUPTIBLE	66	6
Total Revenues from Transportation of Gas of Others (489)	**1,380**	
Rent from Gas Property (493):		
NONE		7
Total Rent from Gas Property (493)	**0**	
Other Gas Revenues (495):		
SALES AND USE TAX HANDLING	10	8
Total Other Gas Revenues (495)	**10**	
Penalty Revenue (497):		
NONE		9
Total Penalty Revenue (497)	**0**	
Utility Revenue Incentive (PBR) (498):		
NONE		10
Total Utility Revenue Incentive (PBR) (498)	**0**	

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
MANUFACTURED GAS PRODUCTION EXPENSES					
Operation Supervision and Engineering (710)			**0**		**1**
Steam Expenses (711)			**0**		**2**
Other Power Expenses (712)			**0**		**3**
Liquefied Petroleum Gas Expenses (717)			**0**		**4**
Liquefied Petroleum Gas (728)		1,042	**1,042**	875	**5**
Miscellaneous Production Expenses (735)			**0**		**6**
Rents (736)		21	**21**		**7**
Maintenance Supervision and Engineering (740)			**0**		**8**
Maintenance of Structures and Improvements (741)			**0**		**9**
Maintenance of Production Equipment (742)			**0**		**10**
Total Manufactured Gas Production Expenses	**0**	**1,063**	**1,063**	**875**	
OTHER GAS SUPPLY EXPENSES					
Natural Gas City Gate Purchases (804)	51	130,232	**130,283**	105,556	**11**
Liquefied Natural Gas Purchases (804.1)			**0**		**12**
Total Other Gas Supply Expenses	**51**	**130,232**	**130,283**	**105,556**	
GAS TRANSMISSION EXPENSES					
Other Gas Purchases (805)			**0**		**13**
Total Gas Transmission Expenses	**0**	**0**	**0**	**0**	
OTHER GAS SUPPLY EXPENSES					
Purchased Gas Cost Adjustments (805.1)		(2,153)	**(2,153)**	2,654	**14**
Incremental Gas Cost Adjustments (805.2)			**0**		**15**
Exchange Gas (806)			**0**		**16**
Purchased Gas Expenses (807)			**0**		**17**
Gas Withdrawn from Storage -- Debit (808.1)			**0**		**18**
(Less) Gas Delivered to Storage -- Credit (808.2)			**0**		**19**
Withdrawals of Liquefied Natural Gas held for Processing -- debit (809.1)			**0**		**20**
(Less) Deliveries of Natural Gas for Processing -- Credit (809.2)			**0**		**21**
(Less) Gas Used for Compressor Station Fuel -- Credit (810)			**0**		**22**
(Less) Gas Used for products Extraction -- Credit (811)			**0**		**23**
(Less) Gas Used for Other Utility Operations -- Credit (812)			**0**		**24**
Other Gas Supply Expenses (813)	22	24	**46**	357	**25**
Total Other Gas Supply Expenses	**22**	**(2,129)**	**(2,107)**	**3,011**	
OTHER STORAGE EXPENSES					
Operation Supervision and Engineering (840)	11	13	**24**	120	**26**
Operation Labor and Expenses (841)	72	28	**100**	74	**27**
Rents (842)		9	**9**		**28**

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
OTHER STORAGE EXPENSES					
Fuel (842.1)			**0**		**29**
Power (842.2)			**0**		**30**
Gas Losses (842.3)			**0**		**31**
Maintenance Supervision and Engineering (843.1)			**0**		**32**
Maintenance of Structures and Improvements (843.2)			**0**		**33**
Maintenance of Gas Holders (843.3)			**0**		**34**
Maintenance of Purification Equipment (843.4)			**0**		**35**
Maintenance of Liquefaction Equipment (843.5)	12		**12**	14	**36**
Maintenance of Vaporizing Equipment (843.6)	4		**4**	6	**37**
Maintenance of Compressor Equipment (843.7)	3		**3**	2	**38**
Maintenance of Measuring and Regulating Station Equipment (843.8)	1		**1**	3	**39**
Maintenance of Other Equipment (843.9)	23		**23**	22	**40**
Total Other Storage Expenses	**126**	**50**	**176**	**241**	
TRANSMISSION EXPENSES					
Operation Supervision and Engineering (850)			**0**		**41**
System Control and Load Dispatching (851)			**0**		**42**
Communication System Expenses (852)			**0**		**43**
Compressor Station Labor and Expenses (853)			**0**		**44**
Gas for Compressor Station Fuel (854)			**0**		**45**
Other Fuel and Power for Compressor Stations (855)			**0**		**46**
Mains Expenses (856)			**0**		**47**
Measuring and Regulating Station Expenses (857)			**0**		**48**
Transmission and Compression of Gas by Others (858)			**0**		**49**
Other Expenses (859)			**0**		**50**
Rents (860)			**0**		**51**
Maintenance Supervision and Engineering (861)			**0**		**52**
Maintenance of Structures and Improvements (862)			**0**		**53**
Maintenance of Mains (863)			**0**		**54**
Maintenance of Compressor Station Equipment (864)			**0**		**55**
Maintenance of Measuring and Regulating Station Equipment (865)			**0**		**56**
Maintenance of Communication Equipment (866)			**0**		**57**
Maintenance of Other Equipment (867)			**0**		**58**
Total Transmission Expenses	**0**	**0**	**0**	**0**	
DISTRIBUTION EXPENSES					
Operation Supervision and Engineering (870)	474	27	**501**	423	**59**
Distribution Load Dispatching (871)	82	403	**485**	82	**60**
Compressor Station Labor and Expenses (872)			**0**		**61**
Compressor Station Fuel and Power (873)			**0**		**62**
Mains and Services Expenses (874)	284	88	**372**	385	**63**
Measuring and Regulating Station Expenses--General (875)	215	93	**308**	266	**64**

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
DISTRIBUTION EXPENSES					
Measuring and Regulating Station Expenses--Industrial (876)	2		**2**		**65**
Measuring and Regulating Station Expenses--City Gate Check Stations (877)	7	1	**8**		**66**
Meter and House Regulator Expenses (878)	340	(249)	**91**	269	**67**
Customer Installations Expenses (879)	298	3	**301**	400	**68**
Other Expenses (880)	570	923	**1,493**	1,587	**69**
Rents (881)		280	**280**		**70**
Maintenance Supervision and Engineering (885)	4	18	**22**	139	**71**
Maintenance of Structures and Improvements (886)			**0**		**72**
Maintenance of Mains (887)	219	109	**328**	296	**73**
Maintenance of Compressor Station Equipment (888)			**0**		**74**
Maintenance of Measuring and Regulating Station Equipment--General (889)	19	37	**56**	51	**75**
Maintenance of Measuring and Regulating Station Equipment--industrial (890)			**0**		**76**
Maintenance of Measuring and Reg. Station Equip.--City Gate Check Stations (891)	13	1	**14**	5	**77**
Maintenance of Services (892)	128	105	**233**	184	**78**
Maintenance of Meters and House Regulators (893)	278	35	**313**	350	**79**
Maintenance of Other Equipment (894)			**0**		**80**
Total Distribution Expenses	**2,933**	**1,874**	**4,807**	**4,437**	
CUSTOMER ACCOUNTS EXPENSES					
Supervision (901)	6	(1)	**5**	5	**81**
Meter Reading Expenses (902)	709	201	**910**	885	**82**
Customer Records and Collection Expenses (903)	704	1,305	**2,009**	1,827	**83**
Uncollectible Accounts (904)		447	**447**	427	**84**
Miscellaneous Customer Accounts Expenses (905)		203	**203**	167	**85**
Total Customer Accounts Expenses	**1,419**	**2,155**	**3,574**	**3,311**	
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
Supervision (907)			**0**		**86**
Customer Assistance Expenses (908)	276	802	**1,078**	1,187	**87**
Informational and Instructional Advertising Expenses (909)		128	**128**	61	**88**
Miscellaneous Customer Service and Informational Expenses (910)			**0**	28	**89**
Total Customer Service and Informational Expenses	**276**	**930**	**1,206**	**1,276**	
SALES EXPENSES					
Supervision (911)			**0**		**90**
Demonstrating and Selling Expenses (912)	51	85	**136**	93	**91**
Advertising Expenses (913)			**0**		**92**

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
SALES EXPENSES					
Miscellaneous Sales Expenses (916)			**0**		**93**
Total Sales Expenses	**51**	**85**	**136**	**93**	
ADMINISTRATIVE AND GENERAL EXPENSES					
Administrative and General Salaries (920)	1,146		**1,146**	1,113	**94**
Office Supplies and Expenses (921)		1,131	**1,131**	1,136	**95**
(Less) Administrative Expenses Transferred -- Credit (922)		315	**315**	226	**96**
Outside Services Employed (923)		253	**253**	363	**97**
Property Insurance (924)		94	**94**	126	**98**
Injuries and Damages (925)	50	215	**265**	1,345	**99**
Employee Pensions and Benefits (926)	1,014		**1,014**	475	**100**
Franchise Requirements (927)			**0**		**101**
Regulatory Commission Expenses (928)		201	**201**	180	**102**
(Less) Duplicate Charges -- Credit (929)		146	**146**	166	**103**
General Advertising Expenses (930.1)		66	**66**	87	**104**
Miscellaneous General Expenses (930.2)	25	57	**82**	134	**105**
Rents (931)		373	**373**	354	**106**
Maintenance of General Plant (935)		5	**5**	(60)	**107**
Total Administrative and General Expenses	**2,235**	**1,934**	**4,169**	**4,861**	
Total Operation and Maintenance Expenses	**7,113**	**136,194**	**143,307**	**123,661**	

DETAIL OF NATURAL GAS CITY GATE PURCHASES, ACCT. 804

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)	
PURCHASED GAS EXPENSES					
Wages and Salaries (804.11)	51		**51**	55	**1**
Supplies and Expenses (804.12)			**0**	9	**2**
Miscellaneous Purchased Gas Expenses (804.13)			**0**		**3**
Gas Contract Reservation Fees (804.21)		214	**214**	312	**4**
Gas Contract Commodity Costs (804.22)		103,821	**103,821**	64,414	**5**
Spot Gas Commodity Costs (804.23)		19,637	**19,637**	28,319	**6**
Other Gas Purchases (804.24)		485	**485**	(257)	**7**
Gas Surcharges (804.25)			**0**		**8**
Financial Instruments Expenses (804.26)		(6)	**(6)**	428	**9**
Gas Purchase Miscellaneous Expenses (804.27)			**0**		**10**
Gas Costs for Opportunity Sales (804.28)		8,427	**8,427**	6,854	**11**
(Less) Purchased Gas Sold -- Credit (804.32)		8,427	**8,427**	6,854	**12**
(Less) Gas Commodity Cost Transferred to Storage -- Credit (804.33)		19,815	**19,815**	13,242	**13**
(Less) Gas Used in Utility Operations -- Credit (804.34)			**0**		**14**
(Less) Gas Used for Transmission Pumping & Compression -- Credit (804.35)		2,276	**2,276**	2,083	**15**
Total Purchased Gas Expenses	**51**	**102,060**	**102,111**	**77,955**	
TRANSMISSION EXPENSES					
Transmission Contract Reservation Fees (804.41)		11,459	**11,459**	10,822	**16**
Commodity Transmission Fees (804.42)		(986)	**(986)**	511	**17**
Gas Transmission Surcharges (804.43)			**0**		**18**
Gas Transmission Fuel Expense (804.44)		2,276	**2,276**	2,083	**19**
No-Notice Service Expenses (804.45)		243	**243**	236	**20**
Other Transmission Fees and Expenses (804.46)			**0**		**21**
Miscellaneous Transmission Expenses (804.48)			**0**		**22**
Penalties, Unauthorized Use and Overrun, Utility (804.49)			**0**		**23**
Penalties, Unauthorized Use and Overrun, End-User (804.51)			**0**		**24**
(Less) Transmission Services Sold -- Credit (804.52)		1,029	**1,029**	1,034	**25**
(Less) Gas Transmission Expenses Transferred to Storage -- Credit (804.53)		443	**443**	459	**26**
(Less) Gas Transmission Expense Used in Operations -- Credit (804.54)			**0**		**27**
Transmission Costs for Opportunity Sales (804.55)			**0**		**28**
Total Transmission Expenses	**0**	**11,520**	**11,520**	**12,159**	
STORAGE EXPENSES					
Storage Reservation Fees (804.61)		1,399	**1,399**	1,337	**29**
Stored Gas Costs for System Use (804.62)		15,253	**15,253**	14,105	**30**
Storage Penalties (804.63)			**0**		**31**
Stored Gas Costs for Opportunity Sales (804.64)			**0**		**32**
(Less) Storage Capacity Released or Sold -- Credit (804.72)			**0**		**33**
(Less) Stored Gas Sold -- Credit (804.73)			**0**		**34**
Total Storage Expenses	**0**	**16,652**	**16,652**	**15,442**	
Total Expenses - Account 804 - Excl Pipeline Refunds	**51**	**130,232**	**0**	**105,556**	

DETAIL OF NATURAL GAS CITY GATE PURCHASES, ACCT. 804

Particulars (a)	Labor Expense (000's) (b)	Other Expense (000's) (c)	Total Expense (000's) (d)	Last Year Total (000's) (e)
Pipeline Refunds (804.06)			0	35
Total Expenses - Account 804	**51**	**130,232**	**130,283**	**105,556**

GAS UTILITY PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (000's) (b)	Additions During Year (000's) (c)	Retirements During Year (000's) (d)	Adjustments Increase or (Decrease) (000's) (e)	Balance End of Year (000's) (f)	
INTANGIBLE PLANT						
Organization (301)					**0**	**1**
Franchises and Consents (302)					**0**	**2**
Miscellaneous Intangible Plant (303)					**0**	**3**
Total Intangible Plant	**0**	**0**	**0**	**0**	**0**	
MANUFACTURED GAS PRODUCTION PLANT						
Land and Land Rights (304)					**0**	**4**
Structures and Improvements (305)					**0**	**5**
Boiler Plant Equipment (306)					**0**	**6**
Other Power Equipment (307)					**0**	**7**
Coke Ovens (308)					**0**	**8**
Producer Gas Equipment (309)					**0**	**9**
Water Gas Generating Equipment (310)					**0**	**10**
Liquefied Petroleum Gas Equipment (311)					**0**	**11**
Oil Gas generating equipment (312)					**0**	**12**
Generating Equipment--Other Processes (313)					**0**	**13**
Coal, Coke, and Ash Handling Equipment (314)					**0**	**14**
Catalytic Cracking Equipment (315)					**0**	**15**
Other Reforming Equipment (316)					**0**	**16**
Purification Equipment (317)					**0**	**17**
Residual Refining Equipment (318)					**0**	**18**
Gas Mixing Equipment (319)					**0**	**19**
Other Equipment (320)					**0**	**20**
Total Manufactured Gas Production Plant	**0**	**0**	**0**	**0**	**0**	
NATURAL GAS STORAGE & PROCESSING - OTHER STORAGE PLANT						
Land and Land Rights (360)	155				**155**	**21**
Structures and Improvements (361)	371	149			**520**	**22**
Gas Holders (362)	1,626				**1,626**	**23**
Purification Equipment (363)	183	101			**284**	**24**
Liquifaction Equipment (363.1)	137				**137**	**25**
Vaporizing Equipment (363.2)	1,032				**1,032**	**26**
Compressor Equipment (363.3)	277	76			**353**	**27**
measuring and Regulating Equipment (363.4)	2				**2**	**28**
Other Equipment (363.5)	1,582	9			**1,591**	**29**
Total Natural Gas Storage & Processing - Other Storage Plant	**5,365**	**335**	**0**	**0**	**5,700**	
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT						
Land and Land Rights (364.1)					**0**	**30**
Structures and Improvements (364.2)					**0**	**31**

GAS UTILITY PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (000's) (b)	Additions During Year (000's) (c)	Retirements During Year (000's) (d)	Adjustments Increase or (Decrease) (000's) (e)	Balance End of Year (000's) (f)	
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT						
LNG Processing Terminal Equipment (364.3)					**0**	**32**
LNG Transportation Equipment (364.4)					**0**	**33**
Measuring and Regulating Equipment (364.5)					**0**	**34**
Compressor Station Equipment (364.6)					**0**	**35**
Communication Equipment (364.7)					**0**	**36**
Other Equipment (364.8)					**0**	**37**
Total Natural Gas Storage & Processing - Base Load LNG Terminaling and Processing Plnt	**0**	**0**	**0**	**0**	**0**	
TRANSMISSION PLANT						
Land and Land Rights (365.1)					**0**	**38**
Rights-of-Way (365.2)					**0**	**39**
Structures and Improvements (366)					**0**	**40**
Mains (367)					**0**	**41**
Compressor Station Equipment (368)					**0**	**42**
Measuring and Regulating Station Equipment (369)					**0**	**43**
Communication Equipment (370)					**0**	**44**
Other Equipment (371)					**0**	**45**
Total Transmission Plant	**0**	**0**	**0**	**0**	**0**	
DISTRIBUTION PLANT						
Land and Land Rights (374)	6				**6**	**46**
Structures and Improvements (375)					**0**	**47**
Mains (376)	66,715	3,114	341		**69,488**	**48**
Compressor Station Equipment (377)					**0**	**49**
Meas. and Reg. Station Equipment - General (378)	1,490	43			**1,533**	**50**
Meas. and Reg. Station Equipment - Cty. Gate (379)	3,503	138			**3,641**	**51**
Services (380)	43,984	1,968	6		**45,946**	**52**
Meters (381)	22,304	736	74		**22,966**	**53**
Meter Installations (382)					**0**	**54**
House Regulators (383)					**0**	**55**
House Regulatory Installations (384)					**0**	**56**
Industrial Measuring and Regulating Station Equipment (385)					**0**	**57**
Other Property on Customers' Premises (386)					**0**	**58**
Other Equipment (387)					**0**	**59**
Asset Retirement Costs for Distribution Plant (388)		2,736			**2,736**	**60**
Total Distribution Plant	**138,002**	**8,735**	**421**	**0**	**146,316**	

GAS UTILITY PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (000's) (b)	Additions During Year (000's) (c)	Retirements During Year (000's) (d)	Adjustments Increase or (Decrease) (000's) (e)	Balance End of Year (000's) (f)		
GENERAL PLANT							
Land and Land Rights (389)	24				**24**		**61**
Structures and Improvements (390)	183				**183**		**62**
Office Furniture and Equipment (391)	103		3		**100**		**63**
Transportation Equipment (392)	637	175			**812**		**64**
Stores Equipment (393)	31	(29)			**2**	*	**65**
Tools, Shop and Garage Equipment (394)	1,178	87			**1,265**		**66**
Laboratory Equipment (395)	470				**470**		**67**
Power-Operated Equipment (396)	756				**756**		**68**
Communication Equipment (397)					**0**		**69**
Miscellaneous Equipment (398)					**0**		**70**
Other Tangible Property (399)					**0**		**71**
Asset Retirement Costs for General Plant (399.1)					**0**		**72**
Total General Plant	**3,382**	**233**	**3**	**0**	**3,612**		
Total utility plant in service	**146,749**	**9,303**	**424**	**0**	**155,628**		

GAS UTILITY PLANT IN SERVICE

Gas Utility Plant in Service (Page G-07)

General footnotes

65. Negative addtions due to 106 reclass to Different 101 Plant Acct.

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (000's) (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (000's) (d)	Accruals During Year: Additional Amount (000's) (e)	
INTANGIBLE PLANT					
Organization (301)					1
Franchises and Consents (302)					2
Miscellaneous Intangible Plant (303)					3
Total Intangible Plant	**0**		**0**	**0**	
MANUFACTURED GAS PRODUCTION PLANT					
Land and Land Rights (304)					4
Structures and Improvements (305)					5
Boiler Plant Equipment (306)					6
Other Power Equipment (307)					7
Coke Ovens (308)					8
Producer Gas Equipment (309)					9
Water Gas Generating Equipment (310)					10
Liquefied Petroleum Gas Equipment (311)					11
Oil Gas generating equipment (312)					12
Generating Equipment--Other Processes (313)					13
Coal, Coke, and Ash Handling Equipment (314)					14
Catalytic Cracking Equipment (315)					15
Other Reforming Equipment (316)					16
Purification Equipment (317)					17
Residual Refining Equipment (318)					18
Gas Mixing Equipment (319)					19
Other Equipment (320)					20
Total Manufactured Gas Production Plant	**0**		**0**	**0**	
NATURAL GAS STORAGE & PROCESSING - OTHER STORAGE PLANT					
Land and Land Rights (360)					21
Structures and Improvements (361)	325	3.66%	16		22
Gas Holders (362)	1,788	0.00%	0		23
Purification Equipment (363)	170	2.41%	6		24
Liquifaction Equipment (363.1)	138	0.00%	0		25
Vaporizing Equipment (363.2)	773	3.13%	33		26
Compressor Equipment (363.3)	277	2.89%	9		27
measuring and Regulating Equipment (363.4)	2	0.00%	0		28
Other Equipment (363.5)	1,231	2.03%	32		29
Total Natural Gas Storage & Processing - Other Storage Plant	**4,704**		**96**	**0**	
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT					
Land and Land Rights (364.1)					30
Structures and Improvements (364.2)					31
LNG Processing Terminal Equipment (364.3)					32

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

Account (a)	Book Cost of Plant Retired (000's) (f)	Cost of Removal (000's) (g)	Salvage (000's) (h)	Adjustments Increase or (Decrease) (000's) (i)	Balance End of Year (000's) (j)	
301					0	1
302					0	2
303					0	3
	0	0	0	0	0	
304					0	4
305					0	5
306					0	6
307					0	7
308					0	8
309					0	9
310					0	10
311					0	11
312					0	12
313					0	13
314					0	14
315					0	15
316					0	16
317					0	17
318					0	18
319					0	19
320					0	20
	0	0	0	0	0	
360					0	21
361					341	22
362					1,788	23
363					176	24
363.1					138	25
363.2					806	26
363.3					286	27
363.4					2	28
363.5					1,263	29
	0	0	0	0	4,800	
364.1					0	30
364.2					0	31
364.3					0	32

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (000's) (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (000's) (d)	Accruals During Year: Additional Amount (000's) (e)		
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT						
LNG Transportation Equipment (364.4)						33
Measuring and Regulating Equipment (364.5)						34
Compressor Station Equipment (364.6)						35
Communication Equipment (364.7)						36
Other Equipment (364.8)						37
Total Natural Gas Storage & Processing - Base Load LNG Terminaling and Processing Plnt	**0**		**0**	**0**		
TRANSMISSION PLANT						
Land and Land Rights (365.1)						38
Rights-of-Way (365.2)						39
Structures and Improvements (366)						40
Mains (367)						41
Compressor Station Equipment (368)						42
Measuring and Regulating Station Equipment (369)						43
Communication Equipment (370)						44
Other Equipment (371)						45
Total Transmission Plant	**0**		**0**	**0**		
DISTRIBUTION PLANT						
Land and Land Rights (374)						46
Structures and Improvements (375)						47
Mains (376)	28,085	2.88%	1,952			48
Compressor Station Equipment (377)			0			49
Meas. and Reg. Station Equipment - General (378)	831	4.40%	66			50
Meas. and Reg. Station Equipment - Cty. Gate (379)	1,276	3.67%	132			51
Services (380)	28,714	5.31%	2,371			52
Meters (381)	10,147	4.20%	955			53
Meter Installations (382)						54
House Regulators (383)						55
House Regulatory Installations (384)						56
Industrial Measuring and Regulating Station Equipment (385)						57
Other Property on Customers' Premises (386)						58
Other Equipment (387)						59
Asset Retirement Costs for Distribution Plant (388)						60
Total Distribution Plant	**69,053**		**5,476**	**0**		
GENERAL PLANT						
Land and Land Rights (389)						61
Structures and Improvements (390)	139	3.14%	6			62
Office Furniture and Equipment (391)	90	0.00%	5		*	63
Transportation Equipment (392)	307	0.00%	61		*	64
Stores Equipment (393)	2	5.00%	1			65

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

Account (a)	Book Cost of Plant Retired (000's) (f)	Cost of Removal (000's) (g)	Salvage (000's) (h)	Adjustments Increase or (Decrease) (000's) (i)	Balance End of Year (000's) (j)		
364.4					**0**		**33**
364.5					**0**		**34**
364.6					**0**		**35**
364.7					**0**		**36**
364.8					**0**		**37**
	0	**0**	**0**	**0**	**0**		
365.1					**0**		**38**
365.2					**0**		**39**
366					**0**		**40**
367					**0**		**41**
368					**0**		**42**
369					**0**		**43**
370					**0**		**44**
371					**0**		**45**
	0	**0**	**0**	**0**	**0**		
374					**0**		**46**
375					**0**		**47**
376	341	50			**29,646**		**48**
377					**0**		**49**
378					**897**		**50**
379		4			**1,404**		**51**
380	6				**31,079**		**52**
381	74				**11,028**		**53**
382					**0**		**54**
383					**0**		**55**
384					**0**		**56**
385					**0**		**57**
386					**0**		**58**
387					**0**		**59**
388					**0**		**60**
	421	**54**	**0**	**0**	**74,054**		
389					**0**		**61**
390					**145**		**62**
391	3				**92**	*	**63**
392					**368**	*	**64**
393					**3**		**65**

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (000's) (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (000's) (d)	Accruals During Year: Additional Amount (000's) (e)		
GENERAL PLANT						
Tools, Shop and Garage Equipment (394)	520	5.00%	60			**66**
Laboratory Equipment (395)	240	5.00%	23			**67**
Power-Operated Equipment (396)	234	0.00%	53		*	**68**
Communication Equipment (397)		10.00%				**69**
Miscellaneous Equipment (398)		5.00%				**70**
Other Tangible Property (399)						**71**
Asset Retirement Costs for General Plant (399.1)						**72**
Retirement Work in Progress						**73**
Total General Plant	**1,532**		**209**	**0**		
Total accum. prov. for depreciation	**75,289**		**5,781**	**0**		

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

Account (a)	Book Cost of Plant Retired (000's) (f)	Cost of Removal (000's) (g)	Salvage (000's) (h)	Adjustments Increase or (Decrease) (000's) (i)	Balance End of Year (000's) (j)		
394					580		66
395					263		67
396					287	*	68
397					0		69
398					0		70
399					0		71
399.1					0		72
RWIP					0		73
	3	0	0	0	1,738		
	424	54	0	0	80,592		

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Accumulated Provision for Depreciation - Gas (Page G-08)

General footnotes

63. Various Rates are in this account.
64 Various Rates are in this account.
68. Various Rates are in this account.

Balance End of Year includes $437 (000's) of gas retirement work in progress.

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

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GAS STORED (ACCOUNTS 117, 164.1, 164.2 AND 164.3)

1. If during the year, adjustment was made to the stored gas inventory (such as to correct cumulative inaccuracies of gas measurements), furnish in a footnote an explanation for the reason for the adjustment, the MCF and dollar amount of the adjustment, and account charged or credited.
2. Give in a footnote, a concise statement of the facts and the accounting performed with respect to any enroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
3. If the company uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
4. If the company has provided accumulated provision for stored gas, which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of FERC authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, and (e) a summary showing balance of accumulated provision and entries during the year.
5. Report pressure base of gas volumes as 14.73 psia at 60 Degrees F. (See Note 1)

Description (a)	Noncurrent (Acct. 117) (b)	Current (Acct. 164.1) (c)	LNG (Acct. 164.2) (d)	LNG (Acct. 164.3) (e)	Total (f)	
Balance at Beginning of Year (000's)		9,187	37		**9,224**	1
Gas Delivered to Storage (000's)		19,793	465		**20,258**	2
Gas Withdrawn from Storage (contra Account) (000's)		(14,745)	(239)		**(14,984)**	3
						4
Other Debits or Credits (Net) (000's)		0			**0**	5
Balance at End of Year (000's)	**0**	**14,235**	**263**	**0**	**14,498**	6
Therms (000's)		17,472	343		**17,815**	7
Amount per Therm	**0.000**	**0.815**	**0.767**	**0.000**	**0.814**	8

DETAIL OF STORED GAS ACCOUNT (ACCOUNT 164.1)

1. If during the year, adjustment was made to the stored gas inventory (such as to correct cumulative inaccuracies of gas measurements), furnish in a footnote an explanation for the reason for the adjustment, the MCF and dollar amount of the adjustment, and account charged or credited.
2. Give in a footnote, a concise statement of the facts and the accounting performed with respect to any enroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
3. If the company uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
4. If the company has provided accumulated provision for stored gas, which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of FERC authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, and (e) a summary showing balance of accumulated provision and entries during the year.
5. Report pressure base of gas volumes as 14.73 psia at 60 Degrees F. (See Note 1)

Description (a)	Commodity Storage Fees Acct. 164.11 (b)	Commodity Injection Fees Acct. 164.12 (c)	Commodity Withdrawal Fees Acct. 164.13 (d)	Other Storage Fees Acct. 164.14 (e)	Stored Gas Withdrawn Acct. 164.16 (f)	
Balance at Beginning of Year (000's)		32				1
Gas Delivered to Storage (000's)		33				2
Gas Withdrawn from Storage (contra Account) (000's)		(44)				3
Other Debits or Credits (Net) (000's)						4
Balance at End of Year (000's)	**0**	**21**	**0**	**0**	**0**	5
Therms		17,472				6
Amount per Therm	**0.000**	**0.001**	**0.000**	**0.000**	**0.000**	7

Description (a)	Gas Commodity Costs Transferred to Storage - Debit Acct. 164.33 (g)	Gas Transmission Expense Transferred to Storage - Debit Acct. 164.53 (h)	Stored Gas Withdrawn for System Use Acct. 164.62 (i)	Stored Gas Forfeited Acct. 164.63 (j)	Total Acct. 164.1 (k)	
Balance at Beginning of Year (000's)	8,878	277			9,187	8
Gas Delivered to Storage (000's)	19,360	400			**19,793**	9
Gas Withdrawn from Storage (contra Account) (000's)	(14,311)	(390)			**(14,745)**	10
Other Debits or Credits (Net) (000's)					**0**	11
Balance at End of Year (000's)	**13,927**	**287**	**0**	**0**	**14,235**	12
Therms	17,472	17,472			17,472	13
Amount per Therm	**0.797**	**0.016**	**0.000**	**0.000**	**0.815**	14

LIQUEFIED NATURAL GAS STORED (ACCT. 164.2 - 164.3)

Particulars (a)	Amount (000's) (b)	Amount Therms (c)	
Balance, beginning of year	37	83,630	1
Gas delivered to storage	465	634,410	2
Gas withdrawn from storage (debit account 808)	239	374,880	3
Other transactions or adjustments (explain):			
NONE			4
Balance, end of year	**263**	**343,160**	

LIQUEFIED NATURAL GAS STORAGE STATISTICS

Location of Plant (a)	Total Storage Capacity Therms (b)	Maximum Daily Capacity Therms (c)	Total Investment End of Year (000's) (d)	Maximum Day's Withdrawal (000's) (e)	Total Production Expense for Year (000's) (f)	
Eau Claire, WI	2,969,175	180,000	4,500	0	0	1
La Crosse, WI	1,439,600	0	894	0	0	2

GAS PRODUCTION STATISTICS

Location of Plant (a)	Type of Plant (b)	Maximum Daily Capacity Dekatherms (c)	Threms Produced During Year (d)	Total Investment End of Year (000's) (e)	Total Production Expense for Year (000's) (f)		
New Richmond, WI	Propane Air	4,080	0	99			1
Tomah, WI	Propane Air	0	0	207	0	*	2
		4,080	**0**	**306**	**0**		

GAS PRODUCTION STATISTICS

Gas Production Statistics (Page G-14)

General footnotes

2. The propane air plant is used only as back-up supply to Fort McCoy.

GAS HOLDERS

	Telescopic & Piston Holders		Pressure Holders				
Location (a)	Number (b)	Capacity Therms (c)	Number (d)	Capacity at Atmospheric Pressure (e)	Design Pressure (f)	Operated Pressure (g)	
NONE							1

LIQUID PETROLEUM GAS STORAGE

Record hereunder number of liquid petroleum gas storage tanks and total capacity in gallons by location.

Location (a)	Number of Tanks (b)	Water Capacity (c)	
New Richmond, WI	1	25,500	**1**
Tomah, WI	3	30,600	**2**

PURCHASED GAS

Report below the specified information for each point of metering.

Name of Vendor (a)	Point of Metering (b)	Type of Gas Purchased (c)	Therms of Gas Purchased (d)	Total Cost of Gas Purchased (000's) (e)	
	Ashland, WI	Natural	8,652,420	0	1
	Bayfield, WI	Natural	1,096,500		2
	Bergland, MI	Natural	160,470	0	3
	Bessemer, MI	Natural	2,554,630	0	4
	BH Acres, WI	Natural	309,840	0	5
	Butternut, WI	Natural	229,060	0	6
	Chippewa Falls, WI	Natural	11,529,040	0	7
	Colfax, WI	Natural	17,719,570	0	8
	Control	Natural		130,232 *	9
	Eau Claire LNG	Natural	(259,530)	0	10
	Eau Claire, WI	Natural	28,738,060	0	11
	Ewen, MI	Natural	214,680	0	12
	Fall Creek, WI	Natural	766,600	0	13
	Fifield, WI	Natural	135,460	0	14
	Glidden, WI	Natural	296,760	0	15
	Hudson, WI	Natural	10,283,430	0	16
	Hurley, WI	Natural	1,446,220	0	17
	Ind Mt Ski, MI	Natural	0	0	18
	Iron River, WI	Natural	412,460	0	19
	Ironwood, MI	Natural	4,559,940	0	20
	Kinnickinnic, WI	Natural	795,480	0	21
	LaCrosse, WI	Natural	48,740,460	0	22
	Marenisco, MI	Natural	331,230	0	23
	Mellen, WI	Natural	614,180	0	24
	Menomonie, WI	Natural	6,534,340	0	25
	Montreal, WI	Natural	361,210	0	26
	New Richmond, WI	Natural	5,980,650	0	27
	Ogema, WI	Natural	137,710	0	28
	Ond Pub School, WI	Natural	0	0	29
	Park Falls, WI	Natural	11,885,910	0	30
	Phillips, WI	Natural	2,623,160	0	31
	Prentice, WI	Natural	712,550	0	32
	Ramsay, MI	Natural	434,700	0	33
	Rib Lake, WI	Natural	527,700	0	34
	Saxon, WI	Natural	47,330	0	35
	Shelby, WI	Natural	1,383,490	0	36
	Tomah-Fort McCoy, WI	Natural	3,871,090	0	37
	Wakefield, MI	Natural	677,810	0	38
	Washburn, WI	Natural	1,353,630	0	39
	Westboro, WI	Natural	113,150	0	40
	Wheaton, WI	Natural	23,473,460	0	41
Total:			**199,444,850**	**130,232**	

PURCHASED GAS (cont.)

	Average Cost Per Therm of Gas Purchased (f)	Maximum Therms Purchased in One Day (g)	Date of Such Maximum Purchase (h)	Average BTU Content per Cubit Foot of Gas (i)		
	0.000	0		1.000		**1**
				1.000		**2**
	0.000	0		1.000		**3**
	0.000	0		1.000		**4**
	0.000	0		1.000		**5**
	0.000	0		1.000		**6**
	0.000	0		1.000		**7**
	0.000	0		1.000		**8**
		1,540,500	01/17/2005	1.000	*	**9**
	0.000	0		0.000		**10**
	0.000	0		1.000		**11**
	0.000	0		1.000		**12**
	0.000	0		1.000		**13**
	0.000	0		1.000		**14**
	0.000	0		1.000		**15**
	0.000	0		1.000		**16**
	0.000	0		1.000		**17**
	0.000	0		1.000		**18**
	0.000	0		1.000		**19**
	0.000	0		1.000		**20**
	0.000	0		1.000		**21**
	0.000	0		1.000		**22**
	0.000	0		1.000		**23**
	0.000	0		1.000		**24**
	0.000	0		1.000		**25**
	0.000	0		1.000		**26**
	0.000	0		1.000		**27**
	0.000	0		1.000		**28**
	0.000	0		1.000		**29**
	0.000	0		1.000		**30**
	0.000	0		1.000		**31**
	0.000	0		1.000		**32**
	0.000	0		1.000		**33**
	0.000	0		1.000		**34**
	0.000	0		1.000		**35**
	0.000	0		1.000		**36**
	0.000	0		1.000		**37**
	0.000	0		1.000		**38**
	0.000	0		1.000		**39**
	0.000	0		1.000		**40**
	0.000	0		1.000		**41**
	0.653					

PURCHASED GAS

Purchased Gas (Page G-17)

General footnotes

9. The cost of gas purchased by metering point is not available.

PURCHASED GAS (cont.)

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GAS MAINS

1. Report mains separately by pipe material, diameter and either within or outside Wisconsin.
2. Identify pipe material as: I (Cast Iron), S (Steel), P (Plastic), Cu (Copper), F (Fiberglass), or O (Other).
3. Explain all reported adjustments as a schedule footnote.
4. For main additions reported in column (e), as a schedule footnote:
   a. Explain how the additions were financed.
   b. If assessed against property owners, explain the basis of the assessments.
   c. If the assessments are deferred, explain.

Pipe Material (a)	Diameter in Inches (c)	Number of Feet: First of Year (d)	Added During Year (e)	Retired During Year (f)	Adjustments Increase or (Decrease) (g)	End of Year (h)		
Within Wisconsin								
Steel								
	2.000	1,087,842	0	0	(19,368)	**1,068,474**	*	1
	4.000	667,114	0	0	62,281	**729,395**	*	2
	8.000	480,025	0	0	(3,470)	**476,555**	*	3
	10.000	9,230	0	0	0	**9,230**		4
	12.000	75,594	0	0	(496)	**75,098**	*	5
	20.000	10,313	0	0	(2,285)	**8,028**	*	6
Total:		**2,330,118**	**0**	**0**	**36,662**	**2,366,780**		
Plastic								
	2.000	5,982,809	0	0	246,510	**6,229,319**	*	7
	4.000	1,820,733	0	0	71,993	**1,892,726**	*	8
	8.000	47,086				**47,086**		9
Total:		**7,850,628**	**0**	**0**	**318,503**	**8,169,131**		
Total Within Wisconsin		**10,180,746**	**0**	**0**	**355,165**	**10,535,911**		
Outside of Wisconsin								
Steel								
	2.000	264,813	0	0	0	**264,813**		10
	4.000	72,636	0	0	0	**72,636**		11
	8.000	50,210	0	0	0	**50,210**		12
	10.000	4,628	0	0	0	**4,628**		13
	20.000	187	0	0	0	**187**		14
Total:		**392,474**	**0**	**0**	**0**	**392,474**		
Plastic								
	2.000	204,061	0	0	1,696	**205,757**	*	15
	4.000	50,344	0	0	0	**50,344**		16
Total:		**254,405**	**0**	**0**	**1,696**	**256,101**		
Total Outside of Wisconsin		**646,879**	**0**	**0**	**1,696**	**648,575**		
Total Utility		**10,827,625**	**0**	**0**	**356,861**	**11,184,486**		

GAS MAINS

Gas Mains (Page G-19)

General footnotes

Additions and retirements reflected in the adjustment column because data reported was based on a beginning and ending year totals for 2005.

Sizes are by range in the Plant Records
Example: 2" and Under or 2" to 4"

GAS SERVICES

Number of services should include only those owned by utility.

Type/Size (a)	Total services first of year: Main to curb (b)	Total services first of year: On customers' premises (c)	Number added during year: Main to curb (d)	Number added during year: On customers' premises (e)		
Gas Services Located in Wisconsin						
Other						
1.500	85,666	84,872	2,094	2,094	*	1
2.000	537	516				2
3.000	57	57				3
4.000	40	38	2			4
6.000	2	2				5
8.000	2	2				6
Total Other:	**86,304**	**85,487**	**2,096**	**2,094**		
Total Within Wisconsin	**86,304**	**85,487**	**2,096**	**2,094**		
Gas Services Located Outside Wisconsin						
Other						
1.500	5,640	5,638	48	48	*	7
2.000	17	17				8
3.000	1	1				9
4.000	3	3				10
Total Other:	**5,661**	**5,659**	**48**	**48**		
Total Outside of Wisconsin	**5,661**	**5,659**	**48**	**48**		
Total Utility:	**91,965**	**91,146**	**2,144**	**2,142**		

GAS SERVICES (cont.)

Number retired during year		Adjustments during year		Total services end of year			
Main to curb (f)	On customers' premises (g)	Main to curb (h)	On customers' premises (i)	Main to curb (j)	On customers' premises (k)		
352	352			87,408	86,614	*	1
				537	516		2
				57	57		3
1				41	38		4
				2	2		5
				2	2		6
353	**352**	**0**	**0**	**88,047**	**87,229**		
353	**352**	**0**	**0**	**88,047**	**87,229**		
16	16			5,672	5,670	*	7
				17	17		8
				1	1		9
				3	3		10
16	**16**	**0**	**0**	**5,693**	**5,691**		
16	**16**	**0**	**0**	**5,693**	**5,691**		
369	**368**	**0**	**0**	**93,740**	**92,920**		

GAS SERVICES

Gas Services (Page G-20)

General footnotes

Data reported was not by type in 2004 only by size.

1. Should be 1 1/2" and Under
7. Should be 1 1/2" and Under

GAS SERVICES (cont.)

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GAS METERS

Number of meters should include only those carried in Utility Plant Account 381.

Particulars (a)	Number End of Year (b)	
Diaphragmed meters (capacity at 1/2 inch water column pressure drop:		1
2,400 cu. ft. per hour or less	104,415	2
Over 2,400 cu. ft. per hour	82	3
Rotary meters	589	4
Orifice meters		5
Total end of year	**105,086**	6
		7
In stock	2,698	8
Locked meters on customers' premises	343	9
Regular meters in customers' use	101,974	10
Prepayment meters in customers' use		11
Meters in company use, included in Account 381	71	12
Total end of year (as above)	**105,086**	13
		14
No. of diaphragmed meters at end of year which compensate for temperature		15
Number of house regulators installed at end of year		16

GAS METERS

Gas Meters (Page G-22)

General footnotes

16. Regulators now combined with meters account 381.

SUMMARY OF GAS ACCOUNT & SYSTEM LOAD STATISTICS

Particulars (a)	Total All Systems Therms (b)	Wisconsin Operations Therms (c)	Out of State Operations Therms (d)	
GAS ACCOUNT				1
Gas produced (gross):				2
Propane - air	**0**	0	0	3
Other gas	**0**	0	0	4
Total gas produced	**0**	**0**	**0**	5
Gas purchased:				6
Natural	**150,596,020**	141,563,208	9,032,812	7
Other gas	**0**	0	0	8
Total gas purchased	**150,596,020**	**141,563,208**	**9,032,812**	9
Add: Gas withdrawn from storage	**23,491,160**	22,082,150	1,409,010	10
Less: Gas delivered to storage	**25,147,570**	23,639,208	1,508,362	11
Total	**148,939,610**	**140,006,150**	**8,933,460**	12
Transport gas received	**50,505,240**	50,505,240	0	13
Total gas delivered to mains	**199,444,850**	**190,511,390**	**8,933,460**	14
Gas sold				15
Gas sold (incl. interdepartmental)	**147,572,365**	138,281,245	9,291,120	16
Gas used by utility	**189,712**	187,671	2,041	17
Transport gas delivered	**51,531,175**	51,531,175	0	18
Total	**199,293,252**	**190,000,091**	**9,293,161**	19
Gas unaccounted for	**151,598**	**511,299**	**(359,701)**	20
				21
SYSTEM LOAD STATISTICS				22
Maximum send-out in any one day	**1,540,500**	1,540,500		23
Date of such maximum		01/17/2005		24
Maximum daily capacity:				25
Total manufactured-gas production capacity	**4,080**	4,080		26
Liquefied natural gas storage capacity	**180,000**	180,000		27
Maximum daily purchase capacity	**1,338,140**	1,338,140		28
Total maximum daily capacity	**1,522,220**	**1,522,220**	**0**	29
Monthly send-out:				30
January	**32,291,640**	30,573,220	1,718,420	31
February	**23,395,560**	22,146,670	1,248,890	32
March	**23,978,030**	22,713,730	1,264,300	33
April	**13,529,500**	12,941,970	587,530	34
May	**11,294,300**	10,815,550	478,750	35
June	**8,994,790**	8,799,260	195,530	36
July	**9,191,350**	9,002,170	189,180	37
August	**8,365,830**	8,189,320	176,510	38
September	**8,207,050**	7,962,200	244,850	39
October	**11,995,910**	11,455,420	540,490	40
November	**19,320,500**	18,355,110	965,390	41
December	**28,880,390**	27,556,770	1,323,620	42
Total send-out	**199,444,850**	**190,511,390**	**8,933,460**	43
Footnotes		*		44

SUMMARY OF GAS ACCOUNT & SYSTEM LOAD STATISTICS

Summary of Gas Account & System Load Statistics (Page G-23)

General footnotes

Information not available to report Maximum Daily Capacity by jurisdiction.

HIRSCHMAN-HERFINDAHL INDEX

The Hirschman-Herfindahl Index (HHI) is a measure of the degree to which competitors have entered utility markets. It is determined by summing the squared market percentages for a particular rate class. For example, if the utility sells 75% of the natural gas in a particular class, marketer A sells 20%, and marketer B sells 5%, the HHI for that class is:

$$75^2 + 20^2 + 5^2 = 5{,}625 + 400 + 25 = 6{,}050$$

If the utility sells all the natural gas in a class, the HHI for that class is 100 squared, or 10,000.

Class (a)	Schedules (b)	Hirschman-Herfindahl Index (c)	Is the Utility the Provider with the Largest Market Share? (d)	
Large General Service	Lg-1	10,000	Yes	1
Residential	Rg-1	10,000	Yes	2
Contract Demand	Gt-2	10,000	No	3
Small Interrruptible	Ig-1	10,000	Yes	4
Firm Commercial	Gg-1	9,770	Yes	5
Interdepartmental	Gg-1, Ig-1	6,070	No	6
Large Interruptible	Ig-1	3,836	No	7

GAS CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Ashland County	
Cities	
ASHLAND	3,348
MELLEN	341
Total Cities:	**3,689**
Villages	
BUTTERNUT	181
Total Villages:	**181**
Towns	
ASHLAND	4
GINGLES	36
JACOBS	274
MORSE	25
SANBORN	297
Total Towns:	**636**
Total Ashland County:	**4,506**
Bayfield County	
Cities	
BAYFIELD	480
WASHBURN	904
Total Cities:	**1,384**
Towns	
BARKSDALE	123
BAYFIELD	165
BAYVIEW	5
EILEEN	14
HUGHES	4
IRON RIVER	308
RUSSELL	274
WASHBURN	6
Total Towns:	**899**
Total Bayfield County:	**2,283**
Chippewa County	
Cities	
CHIPPEWA FALLS	4,047
EAU CLAIRE	759
Total Cities:	**4,806**
Towns	
EAGLE POINT	302
HALLIE	1,631
LAFAYETTE	1,286

Location (a)	Customers End of Year (b)
Chippewa County	
Towns	
WHEATON	67
Total Towns:	**3,286**
Total Chippewa County:	**8,092**
Dunn County	
Cities	
MENOMONIE	3,972
Total Cities:	**3,972**
Villages	
COLFAX	2
ELK MOUND	222
Total Villages:	**224**
Towns	
COLFAX	15
ELK MOUND	21
MENOMONIE	398
RED CEDAR	255
TAINTER	495
Total Towns:	**1,184**
Total Dunn County:	**5,380**
Eau Claire County	
Cities	
ALTOONA	2,132
EAU CLAIRE	19,561
Total Cities:	**21,693**
Villages	
FALL CREEK	318
Total Villages:	**318**
Towns	
BRUNSWICK	113
LINCOLN	1
PLEASANT VALLEY	414
SEYMOUR	493
UNION	367
WASHINGTON	1,484
Total Towns:	**2,872**
Total Eau Claire County:	**24,883**
Iron County	
Cities	
HURLEY	770

GAS CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Iron County	
Cities	
MONTREAL	431
Total Cities:	**1,201**
Towns	
CAREY	1
KIMBALL	51
PENCE	59
SAXON	54
Total Towns:	**165**
Total Iron County:	**1,366**
La Crosse County	
Cities	
LA CROSSE	17,056
ONALASKA	6,064
Total Cities:	**23,120**
Villages	
HOLMEN	2,670
Total Villages:	**2,670**
Towns	
BARRE	43
CAMPBELL	1,486
GREENFIELD	3
HOLLAND	322
MEDARY	253
ONALASKA	1,486
SHELBY	1,510
Total Towns:	**5,103**
Total La Crosse County:	**30,893**
Monroe County	
Towns	
LA FAYETTE	1
Total Towns:	**1**
Total Monroe County:	**1**
Price County	
Cities	
PARK FALLS	1,139
PHILLIPS	789
Total Cities:	**1,928**
Villages	
PRENTICE	277
Total Villages:	**277**

Location (a)	Customers End of Year (b)
Price County	
Towns	
EISENSTEIN	27
ELK	246
FIFIELD	118
HILL	2
LAKE	250
OGEMA	122
PRENTICE	32
WORCESTER	329
Total Towns:	**1,126**
Total Price County:	**3,331**
Saint Croix County	
Cities	
HUDSON	5,224
NEW RICHMOND	3,052
Total Cities:	**8,276**
Villages	
NORTH HUDSON	1,242
Total Villages:	**1,242**
Towns	
ERIN PRAIRIE	1
HUDSON	1,602
KINNICKINNIC	48
RICHMOND	303
STANTON	113
STAR PRAIRIE	50
TROY	243
Total Towns:	**2,360**
Total Saint Croix County:	**11,878**
Taylor County	
Villages	
RIB LAKE	347
Total Villages:	**347**
Towns	
RIB LAKE	16
WESTBORO	77
Total Towns:	**93**
Total Taylor County:	**440**
Total Company:	**93,053**

GAS CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Gas Customers Served (Page G-25)

General footnotes

Monroe County, Town of Lafayette - Fort Mc Coy has 944 meters counted as 1 customer.

Following is a list of customers that are not identified by city, village or town due to a billing system conversion during 2005.

County	Customers
Ashland	5
Bayfield	43
Chippewa	49
Dunn	21
Eau Claire	59
Iron	2
La Crosse	76
Price	17
St. Croix	260
Taylor	3
Total	535

Total Gas Customers Identified by City, Village or Town	93,053
Gas Customers Not Identified by City, Village or Town	535
Total Gas Customers	93,588

APPENDIX

The following items shall be attached to the completed report:

Notes to Financial Statements

Service Territory Maps

(For 2005 report:) If you normally complete any of the following schedules, please attach a copy:

- Electric Plant Leased to Others (FERC p. 213)
- Allowances (FERC pp. 228-229)
- Extraordinary Property Losses (FERC p. 230)
- Unrecovered Plant and Regulatory Study Costs (FERC p. 230)
- Other Regulatory Liabilities (FERC p. 278)
- Depreciation and Amortization of Electric Plant (FERC pp. 336-337)
- Regulatory Commission Expenses (FERC pp. 350-351)
- Common Utility Plant and Expenses (FERC p. 356)
- Pumped Storage Generating Plant Statistics (Large Plants) (FERC pp. 408-409)
- Common Utility Plant and Accumulated Depreciation (Former WI pp. F-52 - F-53)

Other documentation you are requested to provide.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Business and System of Accounts — NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin, a wholly owned subsidiary of Xcel Energy, Inc. (Xcel Energy), and is an operating utility principally engaged in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. NSP-Wisconsin was subject to the regulatory provisions of the PUHCA. NSP-Wisconsin is also subject to regulation by the FERC and state utility commissions. All of NSP-Wisconsin's accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material aspects.

On Aug. 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (Energy Act), significantly changing many federal energy statutes. The Energy Act is expected to have a substantial long-term effect on energy markets, energy investment, and regulation of public utilities and holding company systems by the FERC, the SEC and the DOE. The FERC was directed by the Energy Act to address many areas previously regulated by other governmental entities under the statutes and determine whether changes to such previous regulations are warranted. The issues that the FERC has been required to consider associated with the repeal of the Public Utility Holding Company Act of 1935 (PUHCA) include, but are not limited to, the expansion of the FERC authority to review mergers and sales of public utility companies and the expansion of the FERC authority over the books and records of holding companies and public utility companies previously governed by the SEC and the appropriate cost standard for the provision of non-power goods and services by service companies. The FERC is in various stages of rulemaking on these and other issues. NSP-Wisconsin cannot predict the impact the new rulemakings will have on its operations or financial results, if any.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Company, which operates hydro reservoirs and is 76.41 percent owned; Clearwater Investments, Inc., which owns interests in affordable housing and is 100 percent owned; and NSP Lands, Inc., which holds real estate and is 100 percent owned.

Basis of Accounting — The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). As required by the FERC, NSP-Wisconsin accounts for its investments in majority-owned subsidiaries using the equity method rather than by consolidating their assets, liabilities, revenues and expenses as required by GAAP. Deferred taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, as opposed to their GAAP presentation as net current or long-term assets and liabilities. If GAAP were followed, these 2005 financial statement lines would have values greater/(smaller) than those shown by FERC of :

Net property, plant and equipment	$	89,974,000
Current assets		4,132,000
Current liabilities		1,784,000
Other long-term assets		(48,982,000)
Long-term debt and other long-term liabilities		43,340,000
Operating revenues		96,932,000
Operating expenses		82,402,000
Other income and deductions		652,000
Cash provided by operating activities		772,000
Cash provided by investing activities		(33,321,000)
Cash provided by financing activities		32,490,000

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated.

NSP-Wisconsin has various rate adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. In addition, NSP-Wisconsin presents its revenue, net of any excise or other fiduciary-type taxes or fees. A summary of significant rate adjustment mechanisms follows:

- NSP-Wisconsin's rates include a cost-of-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel in the Wisconsin retail jurisdiction. In Wisconsin, requests can be made for recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.

- NSP-Wisconsin sells firm power and energy in wholesale markets, which are regulated by the FERC. Certain of these rates include monthly wholesale fuel cost-recovery mechanisms.

***Derivative Financial Instruments* —** NSP-Wisconsin utilizes a variety of derivatives, including interest rate swaps and locks and physical and financial commodity based contracts, to reduce exposure to corresponding risks. These contracts consist mainly of options, index or fixed price swaps and basis swaps. For further discussion of NSP-Wisconsin's risk management and derivative activities, see Note 6 to the Financial Statements.

***Property, Plant, Equipment and Depreciation* —** Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses as incurred. Property, plant and equipment also include costs associated with other property held for future use.

NSP-Wisconsin determines the depreciation of its plant by using the straight-line method, which spreads the original cost equally over the plant's useful life. Depreciation expense for NSP-Wisconsin, expressed as a percentage of average depreciable property, for the years ended Dec. 31, 2005 and 2004 was 3.5 percent and 3.3 percent, respectively.

***Allowance for Funds Used During Construction (AFDC)* —** AFDC represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other income (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in NSP-Wisconsin's rate base for establishing utility service rates.

***Environmental Costs* —** Environmental costs are recorded when it is probable NSP-Wisconsin is liable for the costs and the liability can be reasonably estimated. Costs may be deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If several designated responsible parties exist, costs are estimated and recorded only for NSP-Wisconsin's share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs.

Legal Costs – Litigation accruals are recorded when it is probable that NSP-Wisconsin is liable for the costs and the liability can be reasonably estimated. Legal accruals are recorded net of insurance recovery. Legal costs related to settlements are not accrued, but expensed as incurred.

Income Taxes — Xcel Energy and its utility subsidiaries, including NSP-Wisconsin, file consolidated federal and combined and separate state income tax returns. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss. In accordance with the PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company in the consolidated federal or combined state returns. NSP-Wisconsin defers income taxes for all temporary differences between the book and tax bases of assets and liabilities. The tax rates used are those that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Investment tax credits are deferred and their benefits amortized over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes. For more information on income taxes, see Note 4 to the Financial Statements.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Wisconsin uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, asset retirement obligations, decommissioning, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information is obtained or actual amounts are determinable. Those revisions can affect operating results. Each year the depreciable lives of certain plant assets are reviewed and revised, if appropriate.

Cash and Cash Equivalents — NSP-Wisconsin considers investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. Those instruments are primarily commercial paper and money market funds.

Inventory — All inventories are recorded at average cost.

Regulatory Accounting — NSP-Wisconsin accounts for certain income and expense items in accordance with SFAS No. 71 — "Accounting for the Effects of Certain Types of Regulation." Under SFAS No. 71:

- certain costs, which would otherwise be charged to expense, are deferred as regulatory assets based on the expected ability to recover them in future rates; and

- certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation they will be returned to customers in future rates.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. If restructuring or other changes in the regulatory environment occur, NSP-Wisconsin may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Wisconsin's results of operations in the period the write-off is recorded.

Deferred Financing Costs — Deferred debits include deferred financing costs, which are amortized over the remaining maturity periods of the related debt. NSP-Wisconsin's deferred financing costs, net of amortization at Dec. 31, 2005 and 2004 are $1.9 million and $2.0 million, respectively.

***Accounts Receivable and Allowance for Uncollectibles* —** Accounts receivable are stated at the actual billed amount net of write-offs and allowance for uncollectibles. We establish an allowance for uncollectibles based on a reserve policy that reflects our expected exposure to the credit risk of customers.

***Supplemental Cash Flow Disclosures* —** NSP-Wisconsin made cash payments of $21,337,106 for interest (net of amounts capitalized) and $11,004,081 for income taxes (net of refunds received) in 2005. Cash and cash equivalents consist of cash ($0 – Account 131) and working funds ($100,500 – Account 135).

2. Short-Term Borrowings

Notes Payable — NSP-Wisconsin has an intercompany borrowing arrangement with NSP-Minnesota, with interest charged at NSP-Minnesota's short-term borrowing rate. On Dec. 22, 2005, the PSCW issued an order increasing NSP-Wisconsin's borrowing limit from $50 million to $75 million. At Dec. 31, 2005 and 2004, NSP-Wisconsin had short-term borrowings related to this intercompany arrangement of $64.0 million and $31.5 million, respectively. The weighted average interest rates at Dec. 31, 2005 and 2004 were 5.05 percent and 5.25 percent, respectively.

3. Long-Term Debt

All property of NSP-Wisconsin is subject to the lien of its first mortgage indenture.

Maturities of long-term debt are:

(Millions of Dollars)		
2006	$	—
2007		—
2008		80
2009		—
2010		—

4. Income Taxes

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following is a table reconciling such differences for the years ending Dec. 31:

	2005	**2004**
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	5.2	5.0
Tax credits recognized	(1.9)	(0.9)
Regulatory differences — utility plant items	0.1	(0.6)
Resolution of income tax audits	(1.0)	1.2
Other — net	(1.1)	(0.3)
Effective income tax rate	36.3%	39.4%

Income taxes comprise the following expense (benefit) items for the years ending Dec. 31:

(Thousands of Dollars)	**2005**	**2004**
Current federal tax expense	$ 10,352	$ 20,190
Current state tax expense	2,586	8,340
Deferred federal tax expense	2,174	8,412

Deferred state tax expense (benefit)	804	(734)
Deferred investment tax credits	(785)	(789)
Total income tax expense	$ 15,131	$ 35,419

The components of net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

(Thousand of Dollars)	2005	2004
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 164,252	$ 163,911
Employee benefits	22,055	21,076
Regulatory assets	22,646	18,204
Other	5,749	5,597
Total deferred tax liabilities	$ 214,702	$ 208,788
Deferred tax assets:		
Differences between book and tax bases of property	$ 21,695	$ 20,302
Employee benefits	5,120	4,081
Deferred investment tax credits	5,000	5,309
Regulatory liabilities	4,975	4,904
Other	8,938	8,823
Total deferred tax assets	$ 45,728	$ 43,419
Net deferred tax liability	$ 168,974	$ 165,369

5. Benefit Plans and Other Postretirement Benefits

Pension and other postretirement benefit disclosures below generally represent Xcel Energy consolidated information unless specifically identified as being attributable to NSP-Wisconsin.

Xcel Energy offers various benefit plans to its benefit employees, including those of NSP-Wisconsin. Approximately 56 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2005, NSP-Wisconsin had 417 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2007.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees, including those of NSP-Wisconsin. Benefits are based on a combination of years of service, the employee's average pay and Social Security benefits.

Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws.

Pension Plan Assets — Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities. In 2004, Xcel Energy completed a review of its pension plan asset allocation and adopted revised asset allocation targets. The target range for our pension asset allocation is 60 percent in equity investments, 20 percent in fixed income investments and 20 percent in nontraditional investments, such as real estate, timber ventures, private equity and a diversified commodities index.

The actual composition of pension plan assets at Dec. 31 was:

	2005	2004
Equity securities	65%	69%
Debt securities	20	19

Real estate	4	4
Cash	1	1
Nontraditional investments	10	7
	100%	100%

Xcel Energy bases its investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the Xcel Energy portfolio of pension investments is 12.0 percent, which is greater than the current assumption level. The pension cost determinations assume the continued current mix of investment types over the long term. The Xcel Energy portfolio is heavily weighted toward equity securities and includes nontraditional investments that can provide a higher-than-average return. As is the experience in recent years, a higher weighting in equity investments can increase the volatility in the return levels actually achieved by pension assets in any year. Investment returns in 2005 and 2004 exceeded the assumed levels of 8.75 percent and 9.0 percent, respectively. Xcel Energy continually reviews its pension assumptions. In 2006, Xcel Energy will continue to use an investment return assumption of 8.75 percent.

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	**2005**	**2004**
Accumulated Benefit Obligation at Dec. 31	$ 2,642,177	$ 2,575,317
Change in Projected Benefit Obligation		
Obligation at Jan. 1	$ 2,732,263	$ 2,632,491
Service cost	60,461	58,150
Interest cost	160,985	165,361
Plan amendments	300	—
Actuarial loss	85,558	133,552
Settlements	—	(27,627)
Benefit payments	(242,787)	(229,664)
Obligation at Dec. 31	$ 2,796,780	$ 2,732,263
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$ 3,062,016	$ 3,024,661
Actual return on plan assets	254,307	284,600
Employer contributions	20,000	10,046
Settlements	—	(27,627)
Benefit payments	(242,787)	(229,664)
Fair value of plan assets at Dec. 31	$ 3,093,536	$ 3,062,016
Funded Status of Plans at Dec. 31		
Net asset	$ 296,756	$ 329,753
Unrecognized prior service cost	214,702	244,437
Unrecognized loss	281,519	176,957
Xcel Energy net pension amounts recognized on balance sheet	$ 792,977	$ 751,147
NSP-Wisconsin prepaid pension asset recorded	$ 54,767	$ 52,272
Measurement Date	Dec. 31, 2005	Dec. 31, 2004
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	5.75%	6.00%
Expected average long-term increase in compensation level	3.50%	3.50%

Cash Flows **–** Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other pertinent calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in the years 2004 and 2005 for Xcel Energy's pension plans, and are not expected to require cash funding in 2006.

Benefit Costs **—** The components of net periodic pension cost (credit) are:

(Thousands of Dollars)	**2005**	**2004**
Service cost	$ 60,461	$ 58,150
Interest cost	160,985	165,361
Expected return on plan assets	(280,064)	(302,958)
Curtailment gain	—	—
Settlement gain	—	(926)
Amortization of transition asset	—	(7)
Amortization of prior service cost	30,035	30,009
Amortization of net (gain) loss	6,819	(15,207)
Net periodic pension credit under SFAS No. 87	$ (21,764)	$ (65,578)
NSP-Wisconsin		
Net periodic pension credit	$ (2,495)	$ (5,888)
Significant Assumptions Used to Measure Costs		
Discount rate	6.00%	6.25%
Expected average long-term increase in compensation level	3.50%	3.50%
Expected average long-term rate of return on assets	8.75%	9.00%

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2006 pension cost calculations will be 8.75 percent. The cost calculation uses a market-related valuation of pension assets, which reduces year-to-year volatility by recognizing the differences between assumed and actual investment returns over a five-year period.

Xcel Energy and its operating utilities also maintain noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of their operating cash flows.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. The contributions for NSP-Wisconsin were approximately $0.8 million in 2005 and $0.8 million in 2004.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to most Xcel Energy retirees. The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. Employees of the former NSP who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In conjunction with the 1993 adoption of SFAS No. 106 – "Employers' Accounting for Postretirement Benefits Other Than Pension," Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106.

Plan Assets — Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of SFAS No. 106 costs. In 2004, the investment strategy for the union asset fund was changed to increase the exposure to equity funds. Also, a portion of the assets contributed on behalf of non-bargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The actual composition of postretirement benefit plan assets at Dec. 31 was:

	2005	2004
Equity and equity mutual fund securities	61%	54%
Fixed income/debt securities	17	21
Cash equivalents	21	25
Nontraditional Investments	1	—
	100%	100%

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its postretirement health care asset portfolio. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries is presented in the following table:

(Thousands of Dollars)	2005	2004
Change in Benefit Obligation		
Obligation at Jan. 1	$ 929,125	$ 775,230
Service cost	6,684	6,100
Interest cost	55,060	52,604
Plan amendments	—	(1,600)
Plan participants' contributions	12,008	9,532
Actuarial gain (loss)	(3,175)	148,341
Benefit payments	(61,530)	(61,082)
Obligation at Dec. 31	$ 938,172	$ 929,125
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$ 318,667	$ 285,861
Actual return on plan assets	14,507	21,950
Plan participants' contributions	12,008	9,532
Employer contributions	68,211	62,406
Benefit payments	(61,530)	(61,082)
Fair value of plan assets at Dec. 31	$ 351,863	$ 318,667
Funded Status at Dec. 31		
Net obligation	$ 586,309	$ 610,458
Unrecognized transition obligation	(103,022)	(117,600)
Unrecognized prior service cost	15,736	17,914
Unrecognized loss	(364,745)	(383,026)
Accrued benefit liability recorded	$ 134,278	$ 127,746
NSP-Wisconsin accrued benefit liability recorded	$ 5,145	$ 4,603

Significant Assumptions Used to Measure Benefit Obligations

Discount rate for year-end valuation	5.75%	6.00%

Effective Dec. 31, 2004, Xcel Energy raised its initial medical trend assumption from 6.5 percent to 9.0 percent and lowered the ultimate trend assumption from 5.5 percent to 5.0 percent. The period until the ultimate rate is reached also was increased from two years to six years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects on NSP-Wisconsin:

(Millions of Dollars)	
1-percent increase in APBO components at Dec. 31, 2005	$ 3.9
1-percent decrease in APBO components at Dec. 31, 2005	(3.3)
1-percent increase in service and interest components of the net periodic cost	0.3
1-percent decrease in service and interest components of the net periodic cost	(0.2)

Curtailment and settlement gains resulted from activities of some of Xcel Energy's nonregulated subsidiaries.

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy expects to contribute approximately $75 million during 2006.

Benefit Costs — The components of net periodic postretirement benefit cost are:

(Thousands of Dollars)	2005	2004
Service cost	$ 6,684	$ 6,100
Interest cost	55,060	52,604
Expected return on plan assets	(25,700)	(23,066)
Curtailment gain	—	—
Settlement gain	—	—
Amortization of transition obligation	14,578	14,578
Amortization of prior service credit	(2,178)	(2,179)
Amortization of net loss	26,246	21,651
Net periodic postretirement benefit cost under SFAS No. 106	$ 74,690	$ 69,688
NSP-Wisconsin		
Net periodic postretirement benefit cost recognized – SFAS No. 106	$ 2,745	$ 2,394
Significant assumptions used to measure costs (income)		
Discount rate	6.00%	6.25%
Expected average long-term rate of return on assets (before tax)	5.5%-8.5%	5.5%-8.5%

Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans.

(Thousands of Doll ars)	Projected Pension Benefit Payments	Gross Projected Postretirement Healt h Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Healt h Care Benefit Payments
2006	$ 218,093	$ 63,966	$ 4,777	$ 59,189
2007	221,166	65,851	5,196	60,655
2008	228,196	67,635	5,582	62,053
2009	234,663	69,303	5,936	63,367
2010	239,730	70,851	6,248	64,603
2011-2015	1,216,821	366,454	34,719	331,735

6. Derivative Instruments

In the normal course of business, NSP-Wisconsin is exposed to a variety of market risks. Market risk is the potential loss that may occur as a result of changes in the market or fair value of a particular instrument or commodity. NSP-Wisconsin utilizes, in accordance with approved risk management policies, a variety of derivative instruments to mitigate market risk and to enhance our operations. The use of these derivative instruments is discussed in further detail below.

Utility Commodity Price Risk — NSP-Wisconsin is exposed to commodity price risk in their generation and retail distribution operations. Commodity price risk is managed by entering into both long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products, and for various fuels used in the generation and distribution activities. Commodity risk also is managed through the use of financial derivative instruments. NSP-Wisconsin utilizes these derivative instruments to reduce the volatility in the cost of commodities acquired on behalf of our retail customers even though regulatory jurisdiction may provide for a dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments is done consistently with the local jurisdictional cost recovery mechanism. NSP-Wisconsin's risk-management policy allows it to manage market price risk within each rate-regulated operation to the extent such exposure exists, as allowed by regulation.

Interest Rate Risk — NSP-Wisconsin is subject to the risk of fluctuating interest rates in the normal course of business. NSP-Wisconsin's risk-management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options, subject to regulatory approval when required.

Types of and Accounting for Derivative Instruments

NSP-Wisconsin uses a number of different derivative instruments in connection with its utility commodity price and interest rate activities, including forward contracts, futures, swaps and options. All derivative instruments not qualifying for the normal purchases and normal sales exception, as defined by SFAS No. 133 — "Accounting for Derivative Instruments and Hedging Activities," as amended, (SFAS No. 133) are recorded at fair value. The classification of the fair value for these derivative instruments is dependent on the designation of a qualifying hedging relationship. The fair value of derivative instruments not designated in a qualifying hedging relationship is reflected in current earnings. The designation of a cash flow hedge permits the classification of fair value to be recorded within Other Comprehensive Income, to the extent effective. The designation of a fair value hedge permits a derivative instrument's gains or losses to offset the related results of the hedged item in the Statement of Income, to the extent effective.

SFAS No. 133, as amended, requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. NSP-Wisconsin formally documents hedging relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk-management objectives and strategies for undertaking the hedged transaction. NSP-Wisconsin also formally assesses, both at inception and on an ongoing basis, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

Gains or losses on hedging transactions for the sales of energy or energy-related products are primarily recorded as a component of revenue, hedging transactions for fuel used in energy generation are recorded as a component of fuel costs; hedging transactions for natural gas purchased for resale are recorded as a component of natural gas costs; and interest rate hedging transactions are recorded as a component of interest expense. NSP-Wisconsin is allowed to recover in natural gas rates the costs of certain financial instruments acquired to reduce commodity cost volatility.

Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The types of qualifying hedging transactions that NSP-Wisconsin is currently engaged in are discussed below.

Cash Flow Hedges

The effective portion of the change in the fair value of a derivative instrument qualifying as a cash flow hedge is recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument's change in fair value is recognized in current earnings.

***Commodity Cash Flow Hedges* —** NSP-Wisconsin enters into derivative instruments to manage variability of future cash flows from changes in commodity prices. These derivative instruments are designated as cash flow hedges for accounting purposes. At Dec. 31, 2005, NSP-Wisconsin had various commodity-related contracts classified as cash flow hedges extending through March 2006. The fair value of these cash flow hedges is recorded in either Other Comprehensive Income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place. Amounts deferred in these accounts are recorded in earnings as the hedged purchase or sales transaction is settled. This could include the purchase or sale of energy or energy-related products, the use of natural gas to generate electric energy or gas purchased for resale.

As of Dec. 31, 2005, NSP-Wisconsin had no amounts in Accumulated Other Comprehensive Income that is expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

NSP-Wisconsin had no ineffectiveness related to commodity cash flow hedges during the years ended Dec. 31, 2005 and 2004.

Interest Rate Cash Flow Hedges — NSP-Wisconsin enters into interest rate lock agreements, including treasury-rate locks and forward starting swaps, that effectively fix the yield or price on a specified treasury security for a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2005, NSP-Wisconsin had net losses of $0.1 million in Accumulated Other Comprehensive Income that it expects to recognize in earnings during the next 12 months.

NSP-Wisconsin had no ineffectiveness related to interest rate cash flow hedges during the years ended Dec. 31, 2005 and 2004.

Financial Impacts of Qualifying Cash Flow Hedges — The impact of qualifying cash flow hedges on NSP-Wisconsin's Accumulated Other Comprehensive Income, included in the Statement of Stockholder's Equity, is detailed in the following table:

(Millions of Dollars)		
Accumulated other comprehensive loss related to hedges at Dec. 31, 2003	$	(1.1)
After-tax net unrealized gains related to derivatives accounted for as hedges		—

After-tax net realized losses on derivative transactions reclassified into earnings		0.1
Accumulated other comprehensive loss related to hedges at Dec. 31, 2004	$	(1.0)
After-tax net unrealized gains related to derivatives accounted for as hedges		—
After-tax net realized losses on derivative transactions reclassified into earnings		—
Accumulated other comprehensive loss related to hedges at Dec. 31, 2005	$	(1.0)

Fair Value Hedges

The effective portion of the change in the fair value of a derivative instrument qualifying as a fair value hedge is offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the gains or losses of a derivative instrument to offset, in the same period, the gains and losses of the hedged item. The ineffective portion of a derivative instrument's change in fair value is recognized in current earnings. At Dec. 31, 2005, NSP-Wisconsin had no fair value hedges.

Normal Purchases or Normal Sales Contracts

NSP-Wisconsin enters into contracts for the purchase and sale of various commodities for use in its business operations. SFAS No. 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In addition, normal purchases and normal sales contracts must have a price based on an underlying that is clearly and closely related to the asset being purchased or sold. An underlying is a specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event, such as a scheduled payment under a contract.

NSP-Wisconsin evaluates all of its contracts when such contracts are entered to determine if they are derivatives and, if so, if they qualify to meet the normal designation requirements under SFAS No. 133.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under GAAP.

The fair value of qualifying cash flow hedges at Dec. 31, 2005 and 2004 was $0.7 million and $(1.1) million, respectively.

For a further discussion of other financial instruments at NSP-Wisconsin, see Note 7 to the Financial Statements.

7. Financial Instruments

The estimated Dec. 31 fair values of NSP-Wisconsin's recorded financial instruments are as follows:

	2005		2004	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 313,509	$ 321,418	$ 313,476	$ 326,937
Long-term investments	$ 135	$ 135	$ —	$ —

The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates. The fair value of NSP-Wisconsin's long-term debt is estimated based on the quoted market prices for the same or similar issues or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2005 and 2004. These fair value estimates have not been comprehensively revalued for purposes of these Financial Statements since that date, and current estimates of fair values may differ significantly.

NSP-Wisconsin provides a guarantee that guarantees payment or performance under a specified agreement. As a result, NSP-Wisconsin's exposure under the guarantee is based upon the net liability under the specified agreement. The guarantee issued by NSP-Wisconsin limits the exposure of NSP-Wisconsin to a maximum amount stated in the guarantee. The guarantee requires no liability to be recorded, contains no recourse provisions and requires no collateral. On Dec. 31, 2005, NSP-Wisconsin had the following guarantee and exposure related to that guarantee:

(Millions of Dollars) Nature of Guarantee	Guarantor	Guarantee Amount	Current Exposure	Term or Expiration D ate	Triggering Event Requiring Performance	Assets Held as Collateral
NSP-Wisconsin guarantees customer loans to encourage business growth and expansion	NSP-Wisconsin	$ 0.20	$ 0.20	2006	(a)	N/A

(a) Non-timely payment of the obligations or at the time the Debtor becomes the subject of bankruptcy or other insolvency proceedings

Letters of Credit

NSP-Wisconsin may use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2005, there were no letters of credit outstanding.

8. Commitments and Contingent Liabilities

***Leases* —** NSP-Wisconsin leases a variety of equipment and facilities used in the normal course of business. The leases are accounted for as operating leases. Rental expense under operating lease obligations was approximately $4.4 million and $3.5 million for 2005 and 2004, respectively.

Future commitments under operating leases are:

2006	2007	2008	2009	2010	Thereafter
		(Millions of Dollars)			
$ 2.8	$ 1.7	$ 1.2	$ 0.7	$ 0.5	$ 0.4

***Capital Commitments* —** The estimated cost, as of Dec. 31, 2005, of the capital expenditure programs and other capital requirements of NSP-Wisconsin is approximately $66 million in 2006, $67 million in 2007 and $95 million in 2008.

The capital expenditure programs of NSP-Wisconsin are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting NSP-Wisconsin's long-term energy needs. In addition, NSP-Wisconsin's ongoing evaluation of compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Fuel Contracts — NSP-Wisconsin has contracts providing for the purchase and delivery of a significant portion of its current coal and natural gas requirements. These contracts expire in various years between 2006 and 2027. In addition, NSP-Wisconsin may be required to pay additional amounts depending on actual quantities shipped under these agreements. As NSP-Wisconsin does not have an automatic electric fuel adjustment clause for retail customers, NSP-Wisconsin may seek deferred accounting treatment and future rate recovery of increased costs due to an "emergency" event, if that event causes fuel and purchased power costs to exceed the amount included in rates on an annual basis by more than 2 percent.

The estimated minimum purchase for NSP-Wisconsin under these contracts as of Dec. 31, 2005, is as follows:

Coal	Natural Gas Supply	Gas Storage & Transportation
	(Millions of Dollars)	
$ 12	$ 55	$ 90

Joint Operating System - The electric production and transmission system of NSP-Wisconsin is managed as an integrated system with that of NSP-Minnesota, jointly referred to as the NSP System. The electric production and transmission costs of the entire NSP system are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved agreement between the two companies, called the Interchange Agreement, provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

NSP-Minnesota's public liability for claims resulting from any nuclear incident is legally limited to $10.8 billion. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $10.5 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $100.6 million for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs with coverage limits of $2.1 billion for each of NSP-Minnesota's two nuclear plant sites. The insurance also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term, subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the insurance reserve funds to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $6.9 million for business interruption insurance and $26.1 million for property damage insurance if losses exceed accumulated reserve funds.

Environmental Contingencies

NSP-Wisconsin has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Wisconsin is pursuing or intends to pursue insurance claims and believes it will recover some portion of these costs through such claims. Additionally, where applicable, NSP-Wisconsin is pursuing, or intends to pursue, recovery from other potentially responsible parties and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for NSP-Wisconsin, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, NSP-Wisconsin would be required to recognize an expense for such unrecoverable amounts in its Financial Statements.

Site Remediation — NSP-Wisconsin must pay all or a portion of the cost to remediate sites where past activities of NSP-Wisconsin and some other parties have caused environmental contamination. Environmental contingencies could arise from various situations including the following categories of sites:

- sites of former manufactured gas plants (MGP's) operated by NSP-Wisconsin or its predecessors and

- third party sites, such as landfills, to which NSP-Wisconsin is alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes.

NSP-Wisconsin records a liability when enough information is obtained to develop an estimate of the cost of environmental remediation and revises the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, assumptions are made when facts are not fully known. For instance, assumptions may be made about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

Estimates are revised as facts become known. At Dec. 31, 2005, the liability for the cost of remediating these sites was estimated to be $20.3 million, of which $2.7 million was considered to be a current liability. Some of the cost of remediation may be recovered from:

- insurance coverage;

- other parties that have contributed to the contamination; and

- customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. Estimates have been recorded for NSP-Wisconsin's future costs for these sites.

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant Site— NSP-Wisconsin was named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin, which was previously an MGP facility, and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior's Chequemegon Bay adjoining the park.

As an interim action, NSP-Wisconsin proposed, and the Wisconsin Department of Natural Resources (WDNR) approved, a coal tar removal and groundwater treatment system for one area of concern at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002, NSP-Wisconsin installed additional monitoring wells in the deep aquifer under the former MGP site to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002, a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the United States EPA in determining which sites require further investigation. On Dec. 7, 2004, the EPA approved, with minor contingencies, NSP-Wisconsin's proposed work plan to complete the remedial investigation and feasibility study. On Feb. 1, 2005, NSP-Wisconsin submitted its revised work plan to the EPA addressing all of the contingencies raised with the previous proposal. The final approval results in specific delineation of the investigative fieldwork scientific assessments that must be performed. A determination of the scope and cost of the remediation of the Ashland site is not currently expected until 2007 or 2008. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site. In 2005, NSP-Wisconsin spent \$2.8 million in the development of the work plan, the interim response action and other matters related to the site.

The WDNR and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between \$4 million and \$93 million, because different methods of remediation and different results are assumed in each. The EPA and WDNR have not yet selected the method of remediation to use at the site. Until the EPA and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin's level of responsibility, NSP-Wisconsin's liability for the cost of remediating the Ashland site is not determinable. NSP-Wisconsin has recorded a liability of \$19.7 million for its potential liability for remediating the Ashland site. Since NSP-Wisconsin cannot currently estimate the cost of remediating the Ashland site, the recorded liability is based upon the minimum of the estimated range of remediation costs, using information available to date and reasonably effective remedial methods.

On July 2, 2004, the WDNR sent NSP-Wisconsin an invoice for recovery of past costs incurred at the Ashland site between 1994 and March 2003 in the amount of \$1.4 million. On Oct. 19, 2004, the WDNR, represented by the Wisconsin Department of Justice, filed a lawsuit in Wisconsin state court for reimbursement of the past costs. This lawsuit has been stayed until further action by either party. NSP-Wisconsin is reviewing the invoice to determine whether all costs charged are appropriate and has recorded an estimate of its potential liability. All appropriate insurance carriers have been notified of the WDNR's invoice and the lawsuit and will be invited to participate in any future efforts to address the WDNR's actions. All costs paid to the WDNR are expected to be recoverable in rates.

In addition to potential liability for remediation and WDNR oversight costs, NSP-Wisconsin may have liability for natural resource damages, including the assessment thereof (collectively NRDA) at the Ashland site. Section 107 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), as amended, provides that a natural resource damages trustee may recover for injury to, destruction or loss of natural resources, including the reasonable costs of assessment, resulting from releases of hazardous substances. Similarly, Section 311 of the Federal Water Pollution Control Act (or Clean Water Act) provides the federal and state governments with the ability to recover costs incurred in the restoration or replacement of natural resources damaged or destroyed as a result of a hazardous substance discharge. In addition to liability for injuries to or loss of services caused by a release from the Ashland site, NSP-Wisconsin could face exposure for additional indirect injuries that could result from the implementation of various remedial technologies during the cleanup phase of the project. NSP-Wisconsin has indicated to the relevant natural resource trustees its intent to pursue a cooperative assessment approach to the NRDA for the Ashland site whereby the question of natural resource damages is assessed and resolved in tandem with the studies required for selection of a cleanup remedy or remedies. It is, however, unknown at this time whether a cooperative assessment NRDA approach will be adopted at the Ashland site. Therefore, NSP-Wisconsin is not able to estimate its potential exposure for natural resource damages at the site, but has recorded an estimate of its potential liability based upon the minimum of its estimated range of potential exposure.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process. Once approved by the PSCW, deferred MGP remediation costs, less carrying costs, are historically amortized over four or six years. Carrying costs vary directly with the balance in the deferred account and for the period 1995-2005 are estimated to total $1.8 million.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will operate as a credit to ratepayers.

Chippewa Falls Manufactured Gas Plant Site—The WDNR issued an order requiring that NSP-Wisconsin conduct a supplemental site investigation of property owned by NSP-Wisconsin in Chippewa Falls, Wis., which was previously an MGP facility. The supplemental investigation must be conducted in order to determine if additional remediation is required to meet Wisconsin soil and groundwater standards. Based on the results of the supplemental site investigation that was completed during November 2005, the estimated cost to remediate the site is $5.0 million. Once the remediation is completed, it is expected that the WDNR will require long-term annual groundwater monitoring. NSP-Wisconsin is reviewing several options to determine the most cost effective approach to remediate the site. At Dec. 31, 2005, NSP-Wisconsin had not recorded a liability for the cost of remediating this site. Costs accrued for the site would be deferred as a regulatory asset based on the expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers.

Third Party and Other Environmental Site Remediation

Asbestos Removal — Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. NSP-Wisconsin removal costs for asbestos are expected to be immaterial, therefore no asset retirement obligation was recorded. See additional discussion of asset retirement obligations elsewhere in Note 8. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

Clean Air Interstate and Mercury Rules—In March 2005, the EPA issued two significant new air quality rules. The Clean Air Interstate Rule (CAIR) further regulates sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions, and the Clean Air Mercury Rule (CAMR) regulates mercury emissions from power plants for the first time.

The objective of the CAIR is to cap emissions of SO_2 and NOx in the eastern United States, including Wisconsin. When fully implemented, CAIR will reduce SO_2 emissions in 28 eastern states and the District of Columbia by over 70 percent and NOx emissions by over 60 percent from 2003 levels. It is designed to address the transportation of fine particulates, ozone and emission precursors to non-attainment downwind states. CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NO_X that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA's proposed model program, or they can propose another method, which the EPA would need to approve.

Minnesota and Wisconsin will be included in CAIR, and Xcel Energy has generating facilities in these states that will be impacted. Preliminary estimates of capital expenditures associated with compliance with

CAIR for the NSP System range from $30 million to $40 million, which would be a cost sharable through the Interchange Agreement. Xcel Energy is not challenging CAIR in these states.

There is uncertainty concerning implementation of CAIR. States are required to develop implementation plans within 18 months of the issuance of the new rules and have a significant amount of discretion in the implementation details. Legal challenges to CAIR rules could alter their requirements and/or schedule. The uncertainty associated with the final CAIR rules makes it difficult to project the ultimate amount and timing of capital expenditures and operating expenses.

While NSP-Wisconsin expects to comply with the new rules through a combination of additional capital investments in emission controls at various facilities and purchases of emission allowances, it is continuing to review the alternatives. NSP-Wisconsin believes the cost of any required capital investment or allowance purchases will be recoverable from customers.

The EPA's CAMR also uses a national cap-and-trade system and is designed to achieve a 70 percent reduction in mercury emissions. It affects all coal- and oil-fired generating units across the country that are greater than 25 megawatts. Compliance with this rule also occurs in two phases, with the first phase beginning in 2010 and the second phase in 2018. States will be allocated mercury allowances based on coal type and their baseline heat input relative to other states. Each electric generating unit will be allocated mercury allowances based on its percentage of total coal heat input for the state. Similar to CAIR, states can choose to implement an emissions reduction program based on the EPA's proposed model program, or they can propose another method, which the EPA would need to approve.

Under CAMR, NSP-Wisconsin can comply through capital investments in emission controls or purchase of emission "allowances" from other utilities making reductions on their systems. Estimating the cost of compliance with CAMR is difficult because technologies specifically designed for control of mercury are in the early stages of development and there is no established market on which to base the cost of mercury allowances. NSP-Wisconsin's preliminary analysis for Phase I compliance suggests that the costs for compliance beginning in 2010 will not be significant. Further testing is planned during 2006 to confirm these costs or determine whether different measures will be necessary, which could result in higher costs. Additional costs will be incurred to meet Phase II requirements in 2018.

Federal Clean Water Act **—** The Federal Clean Water Act addresses the environmental impacts of cooling water intakes. In July 2004, the EPA published phase II of the rule that applies to existing cooling water intakes at steam-electric power plants. The rule will require NSP-Wisconsin to perform additional environmental studies at two power plants in Wisconsin to determine the impact the facilities may be having on aquatic organisms vulnerable to injury. If the studies determine the plants are not meeting the new performance standards established by the phase II rule, physical and/or operational changes may be required at these plants. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the many uncertainties involved, including unresolved third party legal challenges to the Federal rule. Based on the limited information available, total capital and operating and maintenance costs to the NSP System are estimated at approximately $29.5 million. After costs are shared through the Interchange Agreement, NSP-Wisconsin's estimated cost is $1.5 million over the next five to 10 years. Actual costs may be higher or lower depending on the final resolution of legal challenges to the rule, as well as pending state and federal decisions regarding interpretation of specific rule requirements.

Industrial Boiler Maximum Achievable Control Technology Standards — On Sept. 13, 2004, the EPA published final maximum achievable control technology (MACT) standards for hazardous air pollutants from industrial boilers. Except for the later adoption of the CAMR by the EPA,two boilers at the Bay Front plant would have to comply with this rule by September 2007 at a capital cost estimated to be approximately $10 million. NSP- Wisconsin has determined that CAMR supercedes the effect of the Industrial Boiler MACT Rule on Bay Front. The costs for compliance with CAMR for NSP- Wisconsin, including Bay Front, are not believed to be significant. CAMR is more fully discussed above.

Plant Emissions **—** In October 2000, the EPA reversed a prior decision and found that the French Island plant, an NSP-Wisconsin facility that burns a fuel derived from solid waste, was subject to the federal large combustor regulations. On March 29, 2001, the EPA issued a finding of violation to NSP-Wisconsin. On April 2, 2001, a conservation group also sent NSP-Wisconsin a notice of intent to sue under the citizen suit provisions of the Clean Air Act. On Oct. 20, 2003, the U.S. District Court entered a consent decree settling the EPA's claims against NSP-Wisconsin related to the French Island plant. Pursuant to the terms of that consent decree, NSP-Wisconsin paid a penalty of $500,000. Under the consent decree, the court retains jurisdiction over the plant for several years to monitor compliance with the emission limits and other requirements contained in the decree. Installation of the emission control equipment has been completed and source tests confirm that the plant is now in compliance with the state and federal dioxin standards. NSP-Wisconsin has reached an agreement with La Crosse County through which La Crosse County, the source of the plant's refuse derived fuel, will pay for the emissions equipment through increased waste disposal fees. On Dec. 27, 2005, NSP-Wisconsin received written notice from the EPA that the conditions of the consent decree were fully satisfied and that the consent decree was terminated.

Asset Retirement Obligations

NSP-Wisconsin adopted Statement of Financial Accounting Standard SFAS No. 143 – "Accounting for Asset Retirement Obligations" (SFAS No. 143) effective Jan. 1, 2003. NSP-Wisconsin records future plant removal obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets. This liability will be increased over time by applying the interest method of accretion to the liability, and the capitalized costs will be depreciated over the useful life of the related long-lived assets. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 47 – "Accounting for Conditional Asset Retirement Obligations" (FIN No. 47) to clarify the scope and timing of liability recognition for conditional asset retirement obligations pursuant to SFAS No. 143. The interpretation requires that a liability be recorded for the fair value of an asset retirement obligation, if the fair value is estimable, even when the obligation is dependent on a future event. FIN No. 47 further clarified that uncertainty surrounding the timing and method of settlement of the obligation should be factored into the measurement of the conditional asset retirement obligation rather than affect whether a liability should be recognized. NSP-Wisconsin implemented FIN No. 47 as of Dec. 31, 2005. Included in these financial statements is the recognition of a cumulative change in accounting and disclosure of the liability on a pro forma basis.

Recorded Asset Retirement Obligations (ARO) — NSP-Wisconsin recognized an ARO for the retirement costs of natural gas mains, and for the removal of electric transmission and distribution equipment. The electric transmission and distribution ARO consists of many small potential obligations associated with polychlorinated biphenyls (PCBs), mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured at Dec. 31, 2005. The asset retirement cost was set to this recognized obligation and no cumulative effect adjustment was shown.

A reconciliation of the beginning and ending aggregate carrying amount of NSP-Wisconsin's asset retirement obligations is shown in the table below for the 12 months ended Dec. 31, 2005:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2005	Liabilities Recorded	Liabilities Settled	Accretion	Revisions To Prior Estimates	Ending Balance Dec. 31, 2005
Electric Utility Plant:						
Electric transmission and distribution	$ —	$ 200	$ —	$ —	$ —	$ 200

Gas Utility Plant:						
Gas transmission and distribution	—	2,736		—	—	2,736
Total liability	$ —	$ 2,936	$ —	$ —	$ —	$ 2,936

Cumulative Effect of FIN No. 47 — In March 2005, the FASB issued FIN No. 47. The interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. A summary of the accounting for the initial adoption of FIN No. 47, as of Dec. 31, 2005 is as follows:

(Thousands of Dollars)	**Plant Ass ets**	**Regulato ry Assets**	**Long-Term Liabilitie s**
Reflect retirement obligation when liability incurred	$ 2,936	$ —	$ 2,936
Record accretion of liability to adoption date	—	—	—
Record depreciation of plant to adoption date	—	—	—
Net impact of FASB Interpretation No. 47	$ 2,936	$ —	$ 2,936

Legal Contingencies

In the normal course of business, NSP-Wisconsin is party to routine claims and litigation arising from prior and current operations. NSP-Wisconsin is actively defending these matters and has recorded a liability related to the probable cost of settlement or other disposition, when it can be reasonably estimated.

Carbon Dioxide Emissions Lawsuit — On July 21, 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court for the Southern District of New York against five utilities, including Xcel Energy, to force reductions in carbon dioxide (CO_2) emissions. Although NSP-Wisconsin is not named as a party to this litigation, the requested relief that Xcel Energy cap and reduce its CO2 emissions could have a material adverse effect on NSP-Wisconsin. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. CO_2 is emitted whenever fossil fuel is combusted, such as in automobiles, industrial operations and coal- or gas-fired power plants. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO_2 emissions. In October 2004, Xcel Energy and four other utility companies filed a motion to dismiss the lawsuit, contending, among other reasons, that the lawsuit should be dismissed because it is an attempt to usurp the policy-setting role of the U.S. Congress and the president. On Sept. 19, 2005, the judge granted the defendants' motion to dismiss on constitutional grounds. Plaintiffs have filed a notice of appeal.

The issue of global climate change is receiving increased attention. Debate continues in the scientific community concerning the extent to which the Earth's climate is warming, the causes of climate variations that have been observed, and the ultimate impacts that might result from a changing climate. There also is considerable debate regarding public policy for the approach that the United States should follow to address the issue. The United Nations-sponsored Kyoto Protocol, which establishes greenhouse gas reduction targets for developed nations, entered into force on Feb. 16, 2005. President Bush has declared that the United States will not ratify the protocol and is opposed to legislative mandates, preferring a program based on voluntary efforts and research on new technologies. Xcel Energy is closely monitoring the issue from both scientific and policy perspectives. While it is not possible to know the eventual outcome, Xcel Energy believes the issue merits close attention and is taking actions it believes are prudent to be best positioned for a variety of possible future outcomes. Xcel Energy is participating in a voluntary carbon management program and has established goals to reduce its volume of carbon dioxide emissions by 12 million tons by

2009 and to reduce carbon intensity by 7 percent by 2012. In certain jurisdictions, the evaluation process for future generating resources incorporates the risk of future carbon limits through the use of a carbon cost adder or externality costs. Xcel Energy also is involved in other projects to improve available methods for managing carbon.

9. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy, including NSP-Wisconsin. The services are provided and billed to each subsidiary in accordance with Service Agreements approved by the SEC and executed by each subsidiary. Costs are charged directly to the subsidiary which uses the service whenever possible, and are allocated using an SEC approved method if they cannot be directly assigned.

Utility Engineering Corp. (UE), a former Xcel Energy subsidiary, provided construction services to NSP-Wisconsin, for which it was paid $0.2 million in 2005 and $0.5 million in 2004. UE was sold in April 2005.

The electric production and transmission costs of the entire NSP system are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved agreement (called the “Interchange Agreement”) between the two companies provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs. In 2004, an adjustment was made for $9.8 million, which lowered 2003 costs of NSP-Minnesota shared with NSP-Wisconsin, pursuant to the Interchange Agreement.

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	**2005**	**2004**
Operating revenues:		
Electric utility	$ 0	$ 0
Operating expenses:		
Purchased power	223,528	147,312
Transmission expense	(16,930)	(23,163)
Natural gas purchased for resale	386	303
Other operations – paid to Xcel Energy Services Inc.	50,865	51,335

Accounts receivable and payable with affiliates at Dec. 31 was:

	2005		**2004**	
(Thousands of Dollars)	**Accounts Receivable**	**Accounts Payable**	**Accounts Receivable**	**Accounts Payable**
NSP-Minnesota	$ —	$ 11,756	$ —	$ 2,826
PSCo	2,281	—	—	54
SPS	337	—	7	—
Other subsidiaries of Xcel Energy Inc.	7,513	4,564	1,147	6,685
	$ 10,131	$ 16,320	$ 1,154	$ 9,565

NSP-Wisconsin obtains short-term borrowings from NSP-Minnesota at NSP-Minnesota’s average daily interest rate, including the cost of NSP-Minnesota’s compensating balance requirements. At Dec. 31, 2005 and 2004, NSP-Wisconsin had notes payable outstanding to NSP-Minnesota in the amount of $64.0 million and $31.5 million, respectively. Interest expense related to its borrowings from NSP-Minnesota on NSP-Wisconsin’s statement of income was $1.3 million and $0.3 million for 2005 and 2004, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2006 No. (d)	2006 Amt. (e)
1	Balance-Beginning of Year	7,354.00		1,889.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Allowances Surrendered	1,196.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	6,158.00		1,889.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	17.00		17.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	17.00			
40	Balance-End of Year			17.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	17.00	11,944		
45	Gains		11,944		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2007		2008		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
1,889.00		1,889.00		31,714.00		44,735.00		1
								2
								3
				1,193.00		1,193.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
						1,196.00		20
								21
								22
								23
								24
								25
								26
								27
								28
1,889.00		1,889.00		32,907.00		44,732.00		29
								30
								31
								32
								33
								34
								35
17.00		17.00		867.00		935.00		36
				34.00		34.00		37
								38
				17.00		34.00		39
17.00		17.00		884.00		935.00		40
								41
								42
								43
				17.00	5,058	34.00	17,002	44
					5,058		17,002	45
								46

Schedule Page: 228 Line No.: 44 Column: m

This amount represents the gross proceeds received by Northern States Power Company (Wisconsin). A portion of these proceeds is shared with Northern States Power Company (Minnesota) through the Interchange Agreement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	CHIPPEWA AND FLAMBEAU	CHIPPEWA RESERVOIR LOCATED			
2	IMPROVEMENT COMPANY **	ON CHIPPEWA RIVER NEAR			
3		WINTER, WI.			
4					
5		EXEMPT LICENSED	11/26/1921		2,832,049
6		PROJECT NO. 8286			
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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22					
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33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				2,832,049

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	NONE					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	NONE					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Income Taxes Collected	731,995	190	309,234	77,408	500,169
2						
3	ITC Gross Up	8,866,450	190	517,341		8,349,109
4						
5	Deferred Electric Fuel Cost - Michigan PSCR					
6	-Amortized over 12 month period	396,366	182.3	396,366		
7						
8	Emission Allowances					
9	-Amortization amount per PSCW rate					
10	order 4220-UR-113	134,712	557	39,216	148,517	244,013
11						
12	Capitalized DSM Programs	150,178				150,178
13						
14	Interest on Wisconsin Income Tax Refund					
15	-Amortization amount per PSCW rate					
16	order 4220-UR-113	351,806	431	301,548		50,258
17						
18	Purchased Gas Over/Under Recovery					
19	-Generally amortized over 12 month	2,072,455	805	2,152,612	124,322	44,165
20	period	(27,237)	419	16,928		-44,165
21						
22	Over Recovery of Retirement and					
23	Removal Costs for Orienta Falls Dam					
24	per PSCW rate order 4220-UR-110					
25	-Amortization amount per PSCW rate					
26	order 4220-UR-113	206,136	407	176,688		29,448
27						
28	Deferred Network Transmission					
29	Services (NTS)	7,382				7,382
30						
31	Retail Gas Costs - SFAS 133				728,403	728,403
32						
33	IRC Section 199 Credit				165,960	165,960
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	12,890,243		3,909,933	1,244,610	10,224,920

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			381,190		381,190
2	Steam Production Plant	2,438,321				2,438,321
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	5,308,018		99,018		5,407,036
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	843,498				843,498
7	Transmission Plant	9,651,932				9,651,932
8	Distribution Plant	17,803,080			109,275	17,912,355
9	General Plant	1,163,611			5,527	1,169,138
10	Common Plant-Electric	2,461,727		4,214,690	75,105	6,751,522
11	TOTAL	39,670,187		4,694,898	189,907	44,554,992

B. Basis for Amortization Charges

Account 404
Column (d) Franchises for Hydraulic Production Plant - Conventional is amortized over the license life of the plant and Intangible Plant and Common Plant - Electric (Software) is amortized over its expected useful life of 3, 5, or 7 years.

Account 405
Column (e) Excess AFUDC is amortized over the average life of the property.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	311	13,419					17.70
13	312	65,308					17.70
14	314	7,771					17.00
15	315	5,533					17.10
16	316	2,354					17.60
17	SUBTOTAL STEAM	94,385					
18							
19	331	17,071					27.00
20	332	126,060					27.20
21	333	36,165					27.70
22	334	23,873					27.30
23	335	6,161					24.90
24	SUBTOTAL HYDRO	209,330					
25							
26	341	2,439					10.90
27	342	2,932					8.30
28	343	31,911					12.60
29	344	18,606					11.00
30	345	6,193					10.20
31	346	1,442					8.20
32	SUBTOTAL PEAKING	63,523					
33							
34	352	6,850					
35	353	126,684					
36	354	2,618					
37	355	88,603					
38	356	98,323					
39	357	75					
40	358	223					
41	359	104					
42	SUBTOTAL TRANS	323,480					
43							
44	361	6,941					
45	362	81,116					
46	364	75,681					
47	365	88,189					
48	366	11,910					
49	367	66,062					
50	368	76,613					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	PUBLIC SERVICE COMMISSION OF WISCONSIN				
2	4220-UR-113 2004 Retail Rate Case	27,207		27,207	
3					
4	4220-UR-114 2006 Retail Rate Case	136,652	226,353	363,005	
5					
6	4220-AU-128 Affiliated Interest with Xcel	2,701		2,701	
7	Energy Inc. Money Pool				
8					
9	4220-CE-164 Reconstruct 345KV King to Arpin	12,673		12,673	
10					
11	4220-DU-105 2005 Depreciation Studies	3,756		3,756	
12					
13	4220-GF-108 PGA Filings	2,077		2,077	
14					
15	4220-GP-108 2005-2008 Gas Supply Plan	2,949		2,949	
16					
17	2004-2005 Stray Voltage Assessment	51,953		51,953	
18					
19	Remainder Assessment	481,996		481,996	
20					
21	Miscellaneous Expenses	10,824	61,718	72,542	
22					
23	MICHIGAN PUBLIC SERVICE COMMISSION				
24	Public Utility Assessment	22,249		22,249	
25					
26	Miscellaneous Expenses		8,461	8,461	
27					
28					
29	FEDERAL ENERGY REGULATORY COMMISSION				
30	FERC Assessment	2,505		2,505	
31					
32	Miscellaneous Expenses		94	94	
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	757,542	296,626	1,054,168	

Name of Respondent Northern States Power Company (Wisconsin)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	25,729					2
Gas	928	1,478					3
Electric	928	321,631					4
Gas	928	41,374					5
Electric	928	2,392					6
Gas	928	309					7
							8
Electric	928	12,673					9
							10
Electric	928	3,326					11
Gas	928	430					12
Gas	928	2,077					13
							14
Gas	928	2,949					15
							16
Electric	928	51,953					17
							18
Electric	928	354,189					19
Gas	928	127,807					20
Electric	928	58,613					21
Gas	928	13,929					22
							23
Electric	928	14,342					24
Gas	928	7,907					25
Electric	928	6,101					26
Gas	928	2,360					27
							28
							29
Electric	928	2,505					30
							31
Electric	928	94					32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,054,168					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

SEE INSERT PAGES 356.1 AND 356.2 FOR COMMON UTILITY PLANT AND ACCUMULATED PROVISIONS.

Common Utility Plant classification was included in original cost and reclassification studies filed with the Federal Power Commission on March 30, 1940.

GENERAL BASIS USED IN ALLOCATING TO UTILITY DEPARTMENTS, COMMON UTILITY PLANT AND DEPRECIATION.

COMMON UTILITY PLANT AND DEPRECIATION

Plant and Depreciation provisions are allocated on the basis of average percentages of utility plant in service, gross revenue, and operating expenses (exclusive of joint utility administrative and general expenses, depreciation and taxes) of each department to the total. (Electric 88.63% and Gas 11.37%)

COMMON UTILITY PLANT IN SERVICE

		Allocated to Utility Departments	
Account (a)	Cost at Dec 31, 2005 (b)	Electric (c)	Gas (d)
301 Organization			
303 Misc. Intangible Plant	38,137,489	38,801,257	4,336,232
389 Land and Land Rights	1,919,724	1,701,451	218,273
390 Structures and Improvements	32,623,732	28,914,414	3,709,318
391 Office Furniture & Equipment	7,570,688	6,709,901	860,787
392 Transportation Equipment	1,866,865	1,654.602	212,263
393 Stores Equipment	813,651	721,139	92,512
394 Tools, Shop & Garage Equipment	1,357,061	1,202,763	154,298
395 Laboratory Equipment	31,019	27,492	3,527
396 Power Operated Equipment	258,407	229,026	29,381
397 Communication Equipment	20,403,863	18,803,944	2,319,919
398 Miscellaneous Equipment	78,569	69,636	8,933
Total	105,061,068	93,115,625	11,945,443

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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT HELD FOR FUTURE USE

389 Land and Land Rights	000	000	000

COMMON UTILITY CONSTRUCTION WORK IN PROGRESS

General Plant	2,094,268	1,856,150	238,118

ACCUMULATED PROVISION FOR DEPRECIATION

Item (a)	Common Utility Plant in Service (b)
Balance Beginning of Year	42,255,079
Depreciation accruals for year charged to:	
Common Utility plant expense - General (Acct 403)	2,784,346
Common Utility plant expense - Misc Intangible Plant (Acct 404)	4,816,502
Transportation expense - clearing	144,160
Total Depreciation accruals	7,745,008
Net charges for plant retired	
Book cost of plant retired	(1,604,154)
Cost of Removal	(21,043)
Salvage (credit)	295
Net charges for plant retired	(1,624,902)
Transfers	(2,311)
Balance end of year	48,372,874

COMMON UTILITY ACCUMULATED PROVISION FOR DEPRECIATION
ALLOCATION TO UTILITY DEPARTMENTS

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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

	Electric	Gas	Total
General Plant	42,872,878	5,499,996	48,372,874

COMMOM UTILITY EXPENSES

		Common Cost at Dec 31, 2005	Allocated to Utility Departments Electric	Gas
403	Depreciation Expense	2,784,347	2,461,727	322,620
404	Amortization of Ltd Term Electric Plant	5,197,692	4,214,690	983,002
408.1	Taxes other than income taxes	1,025,086	874,397	150,689
409.1	Income Tax	16,890,486	15,436,722	1,453,764
901	Supervision	(13,877)	(10,330)	(3,547)
902	Meter reading Expense	3,552,385	2,642,724	909,661
903	Customer Records & Collections	9,297,021	6,916,469	2,380,552
904	Uncollectible Accounts	408,715	304,125	104,590
905	Misc. Customer Assistance Expense	495,415	368,484	126,931
908	Customer Assistance Expense	1,608,671	1,252,657	356,014
909	Information & Instructional Expense	72,924	56,788	16,136
912	Demonstration & Selling	474,492	338,771	135,721
920	Administrative & General Salaries	7,192,635	6,363,912	828,723
921	Office Supplies & Expense	5,831,778	5,149,366	682,412
922	Administrative Expenses Transfered	(2,312,603)	(2,044,392)	(268,211)
923	Outside Services	1,881,212	1,663,037	218,175
924	Property Insurance	811,490	717,400	94,090
925	Injury & Damages	1,501,637	1,280,399	221,238
926	Employee Pensions & Benefits	2,459,573	2,097,819	361,754
928	Regulatory Commission	434,721	385,048	49,673
929	Duplicate charge credit	(7,624)	(6,757)	(867)
930.1	General Advertising	566,841	501,550	65,291
930.2	Miscellaneous General	660,202	581,955	78,247
931	Rents	2,559,311	2,263,439	295,872
935	Maintenance of General Plant	43,105	38,097	5,008
Total		63,415,635	53,848,094	9,567,541

Basis of Allocations of Common Utility Expenses

Account 403, 404	3 factor (operating revenue, utility plant in service, supervised o&m)
Account 408.1	3 factor (operating revenue, utility plant in service, supervised o&m), payroll portion-labor

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2006	End of 2005/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account 409.1	pre-tax operating income
Account 901-905	weighted meters billed
Account 906-910	average customer counts
Account 911-917	direct assigned sales expenses
Account 925-926	operating labor
Account 920-935	3 factor (operating revenue, utility plant in service, supervised o&m), all except 925-926

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PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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COMMON UTILITY PLANT AND ACCUMULATED DEPRECIATION

Utility Plant in Service					
Description (Use both title and account number) (a)	Additions during year (b)	Retirements during year (c)	Adjustments dr. or (cr.) (d)	Balance end of year Total (e)	Balance end of year Located in Wis (f)
Intangible plt-common (303)	12,486,438	0	(1,659)	38,137,489	38,137,489
Organization					
Total intangible	12,486,438	0	(1,659)	38,137,489	38,137,489
General plant					
Land & land rights (389)	23,340	0		1,919,724	1,868,595
Structures & improv (390)	3,951,601	39,914	(254,535)	32,623,732	31,660,890
Off furn & fixt (391,391.1)	1,489,351	1,375,431	(81,844)	7,570,688	7,377,624
Transportation equip (392)	995,320	0	0	1,866,865	1,866,865
Stores equip (393)	0	0	0	813,651	807,081
Tools, shop & gar (394)	0	0	0	1,357,061	1,313,942
Laboratory (395)	0	0	0	31,019	30,525
Power operated (396)	0	0	0	258,407	258,407
Communication (397)	21,636	188,809	0	20,403,863	19,648,719
Miscellaneous (398)	0	0	0	78,569	77,064
Other (399)					
Total general plant	6,481,248	1,604,154	(336,379)	66,923,579	64,909,712
Retirement Work in Progress					
TOTAL	18,967,686	1,604,154	(338,038)	105,061,068	103,047,201

ALLOCATION TO UTILITY DEPARTMENTS

Particulars (a)	Plant end of year (b)	Accumulated deprec. end of year (c)	Depreciation accruals (d)
Electric	93,115,625	42,872,878	2,461,727
Gas	11,945,443	5,499,996	322,619
Water			
Steam Heating			
Total	105,061,068	48,372,874	2,784,346

May not cross-check due to rounding.

COMMON UTILITY PLANT AND ACCUMULATED DEPRECIATION (cont.)

Accumulated provision for depreciation							
Straight line accruals Rate (g)	Amount (h)	Additional accruals (i)	Book cost of plant retired (j)	Cost of removal (k)	Salvage (l)	Other additions or (deductions) (m)	Balance end of year (n)
Various		4,816,502				11,736	21,361,864
	0	4,816,502	0	0	0	11,736	21,361,864
2.37	736,594		39,914			(2,311)	7,465,633
Various	555,406		1,375,431			(11,736)	3,254,650
Various	0	115,968			295		546,364
5.00	40,683						573,321
5.00	67,852						633,072
5.00	1,551						15,993
Various	0	28,192					159,256
10.00	1,378,332		188,809				14,400,072
5.00	3,928						52,890
	2,784,346	144,160	1,604,154	0	295	(14,047)	27,101,251
				(25,812)	4,768		(90,241)
	2,784,346	4,960,662	1,604,154	(25,812)	5,063	(2,311)	48,372,874

Explanation of method of allocating common plant, accumulated depreciation, and depreciation expense by utility departments.

Common plant, depreciation reserve and depreciation expense has been allocated to utility departments on the basis of average percentages of utility plant in service, gross revenue and operating expenses (exclusive of joint utility administrative and general expenses, depreciation and taxes) of each department to the total.

Common property under capital leases is not included in these plant numbers.

May not cross-check due to rounding.

Intercompany charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2005*

Service Function	Allocation Method	Amount
Accounting, Fin Rptg & Taxes	Direct Assigned	1,185,368
Accounting, Fin Rptg & Taxes	SEC approved allocator	1,307,328
Aviation Services	Direct Assigned	197,487
Bus Unit Acctg & Budgting-C&FO	Direct Assigned	471,690
Bus Unit Acctg & Budgting-C&FO	SEC approved allocator	75,316
Bus Unit Acctg&Budgeting-EM	Direct Assigned	294,045
Bus Unit Acctg&Budgeting-EM	SEC approved allocator	33,043
Bus Unit Acctg&Budgeting-ES	Direct Assigned	246,092
Bus Unit Acctg&Budgeting-ES	SEC approved allocator	5,060
Bus Unit Acctg-CO Juris Ldr	Direct Assigned	53,916
Bus Unit Acctg-CO Juris Ldr	SEC approved allocator	9,854
Claims Services	Direct Assigned	107,453
Claims Services	SEC approved allocator	8,893
Constr, O&M-A&G	Direct Assigned	518,990
Constr, O&M-A&G	SEC approved allocator	43,843
Constr, O&M-Distribution	Direct Assigned	930,615
Constr, O&M-Distribution	SEC approved allocator	46,457
Constr, O&M-Elec Ops	Direct Assigned	6,135
Constr, O&M-Gas HP/Ops	Direct Assigned	29,122
Constr, O&M-Gas HP/Ops	SEC approved allocator	860
Constr, O&M-Substation	Direct Assigned	43,760
Constr, O&M-Substation	SEC approved allocator	6,865
Constr, O&M-Substation	Direct Assigned	143,558
Constr, O&M-Transm Ops	SEC approved allocator	380
Constr, O&M-Transmission	Direct Assigned	49,712
Constr, O&M-Transmission	SEC approved allocator	3,130
Corp Strategy & Bus Dev	Direct Assigned	389,521
Corp Strategy & Bus Dev	SEC approved allocator	446,848
Corporate Communications	Direct Assigned	556,143
Corporate Communications	SEC approved allocator	951,223
Customer Service	Direct Assigned	4,874,676
Customer Service	SEC approved allocator	38,309
EM - Fuel Procurement	Direct Assigned	117,914
EM - Fuel Procurement	SEC approved allocator	518
EM Reg Trdg-Resource Planning	Direct Assigned	96,232
EM Reg Trdg-Resource Planning	SEC approved allocator	32,439
EM Regulated Trading & Mktg	Direct Assigned	466,343
EM Regulated Trading & Mktg	SEC approved allocator	10,936
Energy Delivery Marketing	Direct Assigned	45,923
Energy Delivery Marketing	SEC approved allocator	1,333
Eng/Design-Common	Direct Assigned	1,388,028
Eng/Design-Common	SEC approved allocator	102,982

Intercompany charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2005*

Service Function	Allocation Method	Amount
Eng/Design-Elec Dist	Direct Assigned	627,939
Eng/Design-Elec Dist	SEC approved allocator	25,824
Eng/Design-Elec Trans/Subst	Direct Assigned	1,529,208
Eng/Design-Elec Trans/Subst	SEC approved allocator	9,436
Eng/Design-Gas Dist	Direct Assigned	212,742
Eng/Design-Gas Dist	SEC approved allocator	9,523
ES Bus Res-Hayden	Direct Assigned	168,743
ES Bus Res-Hayden	SEC approved allocator	94
ES Business Resources	Direct Assigned	285,994
ES Business Resources	SEC approved allocator	223
ES Engineering & Environmental	Direct Assigned	644,774
ES Engineering & Environmental	SEC approved allocator	11,002
Executive Management Services	Direct Assigned	2,110
Executive Management Services	SEC approved allocator	580,988
Facilities & Real Estate	Direct Assigned	3,473,356
Facilities & Real Estate	SEC approved allocator	181,757
Facilities Admin Services	SEC approved allocator	(73)
Finance & Treasury	Direct Assigned	230,638
Finance & Treasury	SEC approved allocator	906,316
Fleet	Direct Assigned	112,572
Fleet	SEC approved allocator	22
Government Affairs	Direct Assigned	633,502
Government Affairs	SEC approved allocator	213,189
Human Resources-C&FO	Direct Assigned	304,548
Human Resources-C&FO	SEC approved allocator	42,878
Human Resources-ES	Direct Assigned	33,800
Human Resources-ES	SEC approved allocator	132
Human Resources-SS	Direct Assigned	830,331
Human Resources-SS	SEC approved allocator	1,218,774
Information Technology - ET	Direct Assigned	775,464
Information Technology - ET	SEC approved allocator	7,790,970
Information Technology-CFO	Direct Assigned	5,938
Information Technology-CFO	SEC approved allocator	75,922
Information Technology-DE-C&FO	Direct Assigned	4,833,415
Information Technology-DE-C&FO	SEC approved allocator	921,484
Information Technology-EM	Direct Assigned	698,483
Information Technology-EM	SEC approved allocator	246,591
Information Technology-ES	Direct Assigned	429,281
Information Technology-ES	SEC approved allocator	140,199
Information Technology-GC	Direct Assigned	15,810
Information Technology-GC	SEC approved allocator	4,992
Information Technology-RE-C&FO	Direct Assigned	1,825,660
Information Technology-RE-C&FO	SEC approved allocator	652,456
Information Technology-SS	Direct Assigned	227,418

Intercompany charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2005*

Service Function	Allocation Method	Amount
Information Technology-SS	SEC approved allocator	233,979
Internal Audit	Direct Assigned	30,489
Internal Audit	SEC approved allocator	155,831
Investor Relations	SEC approved allocator	218,225
Legal	Direct Assigned	299,372
Legal	SEC approved allocator	385,665
Marketing & Sales	Direct Assigned	1,778,890
Marketing & Sales	SEC approved allocator	26,734
Payment & Reporting	Direct Assigned	123,325
Payment & Reporting	SEC approved allocator	38,289
Payroll	Direct Assigned	331
Payroll	SEC approved allocator	101,438
Rates & Regulation	Direct Assigned	787,001
Rates & Regulation	SEC approved allocator	42,859
Receipts Processing	Direct Assigned	94,844
Receipts Processing	SEC approved allocator	693
Supply Chain - C&FO	Direct Assigned	231,765
Supply Chain - C&FO	SEC approved allocator	(25)
Supply Chain - SS	Direct Assigned	(171)
Supply Chain - SS	SEC approved allocator	7,727
Supply Chain Special Programs	SEC approved allocator	6
Supply Chain-ES	Direct Assigned	34,819
Supply Chain-ES	SEC approved allocator	200
TOTAL		50,865,047

* Excludes convenience payments

Appendix A

DESCRIPTION OF SERVICES TO BE PROVIDED BY XCEL ENERGY SERVICES INC. AND DETERMINATION OF CHARGES FOR SUCH SERVICES TO THE OPERATING COMPANIES AND OTHER AFFILIATES

Description of Services Provided

A description of the services provided by Xcel Energy Services is detailed below. Identifiable costs will be directly assigned to the Operating Companies and other affiliates. For costs that are for services of a general nature and cannot be directly assigned, the method of allocation is described below for each service provided. If specific conditions are met (as outlined in the Xcel Energy Services Policies and Procedures Manual), an alternative Labor Dollars Ratio may be used to allocate non-labor costs for any service.

*a) Executive Management Services**

Description – Represents charges for Xcel executive management and services, including, but not limited to, officers of Xcel.

Methods of Allocation – Executive Management indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Asset Ratio.

*b) Investor Relations**

Description – Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Methods of Allocation – Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Asset Ratio.

*c) Internal Audit**

Description – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.

Method of Allocation – Internal Audit indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*d) Legal**

Description - Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Method of Allocation – Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*e) Claims Services**

Description - Provides claims services related to casualty, public and company claims.

Method of Allocation - Claims Services costs will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

*f) Corporate Communications**

Description – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel system. Manages and tracks all contributions made on behalf of the Xcel system.

Method of Allocation – Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*g) Employee Communications**

Description – Develops and distributes communications to employees.

Method of Allocation – Employee Communications indirect costs will be allocated based on the Employee Ratio.

*h) Corporate Strategy & Business Development**

Description – Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Method of Allocation – Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*i) Government Affairs **

Description - Monitors, reviews and researches government legislation.

Method of Allocation – Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*j) Facilities & Real Estate**

Description – Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Method of Allocation – Facilities & Real Estate indirect costs will be allocated to the Operating Companies based on the Square Footage Ratio.

*k) Facilities Administrative Services**

Description – Includes but is not limited to the functions of Mail Delivery, Duplicating and Records Management.

Method of Allocation - Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio

*l) Supply Chain**

Description – Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.

Method of Allocation – Supply Chain will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

*m) Supply Chain Special Programs**

Description – Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Methods of Allocation – Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*n) Human Resources**

Description – Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Methods of Allocation – Human Resources indirect costs will be allocated based on the Employee Ratio.

*o) Finance & Treasury**

Description – Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Method of Allocation – Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*p) Accounting, Financial Reporting & Taxes**

Description - Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Method of Allocation – Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*q) Business Unit Accounting and Budgeting**

Description - Provides financial analysis, budgeting and administrative support for the business units.

Method of Allocation – Business Unit Accounting and Budgeting indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*r) Payment & Reporting**

Description – Processes payments to vendors and prepares statistical reports.

Method of Allocation – Payment & Reporting indirect costs will be allocated to the Operating Companies based on the Invoice Transaction Ratio .

*s) Receipts Processing**

Description – Processes payments received from customers of the Operating Companies and affiliates.

Method of Allocation – Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.

*t) Payroll**

Description – Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Method of Allocation – Payroll indirect costs will be allocated based on the Employee Ratio.

*u) Rates & Regulation**

Description – Determines the Operating Companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Method of Allocation – Rates & Regulation indirect costs will be allocated to the Operating Companies based on the Revenue Ratio or the Labor Dollars Ratio.

*v) Energy Supply Engineering and Environmental**

Description – Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental clean up projects.

Method of Allocation – Energy Supply Engineering and Environmental services will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

*w) Energy Supply Business Resources**

Description - Provides performance, specialists and analytical services to the Operating Companies' generation facilities.

Method of Allocation – Energy Supply Business Resources indirect costs will be allocated using the MWh Generation Ratio.

*x) Energy Markets Regulated Trading & Marketing**

Description - Provides electric trading services to the Operating Companies' electric generation systems including load management, system optimization and resource acquisition.

Method of Allocation – Energy Markets Regulated Trading & Marketing indirect costs will be allocated to the Operating Companies based on the Total MWh Sales Ratio.

*y) Energy Markets – Fuel Procurement**

Description – Purchases fuel for Operating Companies electric generation systems (excluding nuclear).

Method of Allocation – Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.

*z) Energy Delivery Marketing**

Description - Develops new business opportunities and markets the products and services for the Delivery Business Unit.

Method of Allocation – Energy Delivery Marketing will be direct charged.

*aa) Energy Delivery Construction, Operations & Maintenance (COM)**

Description – Constructs, maintains and operates electric and gas delivery systems.

Method of Allocation – Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.

*bb) Energy Delivery Engineering/Design**

Description – Provides engineering and design services in support of capacity planning, construction, operations and material standards.

Method of Allocation – Energy Delivery Engineering/Design services will be direct charged, and administrative support functions that cannot be direct charged will be allocated based on the Labor Dollars Ratio.

*cc) Marketing & Sales**

Description - Provides marketing and sales services for the Operating Companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning and customer service.

Method of Allocation – Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.

*dd) Customer Service**

Description – Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.

Method of Allocation – Customer Service indirect costs will be allocated based on the Customers Ratio.

*ee) Business Systems**

Description – Provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy. They partner with IBM to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace. They work collaboratively with partners and vendors to identify and co-fund opportunities that significantly benefit Xcel Energy's business.

Method of Allocation – Business Systems indirect costs will be allocated using any of the allocation ratios or combination of ratios.

*ff) Aviation Services**

Description – Provides aviation and travel services to employees.

Method of Allocation – Aviation Services will be direct charged.

*gg) Fleet**

Description – Oversees the Operating Companies' Fleet Services Group.

Method of Allocation – Fleet will be direct charged.

*Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and Employee Ratio with number of common officers assigned to Xcel Energy Inc.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc. - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio – Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

Customer Bills Ratio – Based on the average of the monthly total number of customer bills issued during the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Labor Dollars Ratio - Based on the XES department (performing center) labor dollars charged to Operating companies and other affiliates for the month. The numerator of which is the labor dollars charged to an Operating Company or affiliate company and the denominator of which is for all Operating Companies and affiliate companies charged by the department for the month.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas for the prior year ending December 31, the numerator of which is an applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Software Application's Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Transactions with Affiliates Annual Reporting

Regulated Operating Companies

	Amounts Billed to Affiliates	Amounts Billed from Affiliates	Other	Net Intercompany (Payable) Receivable
Northern States Power Company (Minnesota)				
Interchange Agreement	98,604,336	305,202,311	0	(206,597,975)
Customer Receipts/Account Transfers	388,723	(16,578,946)	0	16,967,669
Arpin Settlement Agreement	0	(1,500,000)	0	1,500,000
Customer Refund Checks	(182,070)	0	0	(182,070)
Corporate Software Costs	0	37,774	0	(37,774)
Corporate 1-800 Phone Number Costs	1,163,350	0	0	1,163,350
Emission Allowances	0	(148,517)	0	148,517
Deposits in Transit	0	(2,627,818)	0	2,627,818
Interest on Intercompany Notes Payable	0	1,298,305	0	(1,298,305)
Gas Coordinating Agreement	0	386,349	0	(386,349)
Corporate Owned Life Insurance	0	63,414	0	(63,414)
Remaining (1)	653,178	6,351,830	37,651	(5,661,001)
	100,627,517	292,484,702	37,651	(191,819,534)
Black Mountain Gas (sold by Xcel Energy Inc in October 2003)				
Remaining (1)	0	0	0	0
	0	0	0	0
Public Service Company of Colorado				
Corporate 1-800 Phone Number Costs	1,467,018	0	0	1,467,018
Deferred Compensation	0	62,690	0	(62,690)
FAS 106 Benefit Payments	0	204,973	0	(204,973)
Remaining (1)	92,385	10,170	5,492,142	5,574,357
	1,559,403	277,833	5,492,142	6,773,712
Southwestern Public Service Company				
Corporate 1-800 Phone Number Costs	413,601	0	0	413,601
Corporate Software Costs	0	29,148	0	(29,148)
Remaining (1)	(60,221)	(2,488)	9,165	(48,568)
	353,380	26,660	9,165	335,885
Cheyenne Light Fuel and Power (sold by Xcel Energy Inc in January 2005)				
Remaining (1)	0	0	0	0
	0	0	0	0
	102,540,300	**292,789,195**	**5,538,958**	**(184,709,937)**

This report is prepared in accordance with Docket 4220-AU-127. Additional information is available upon request.

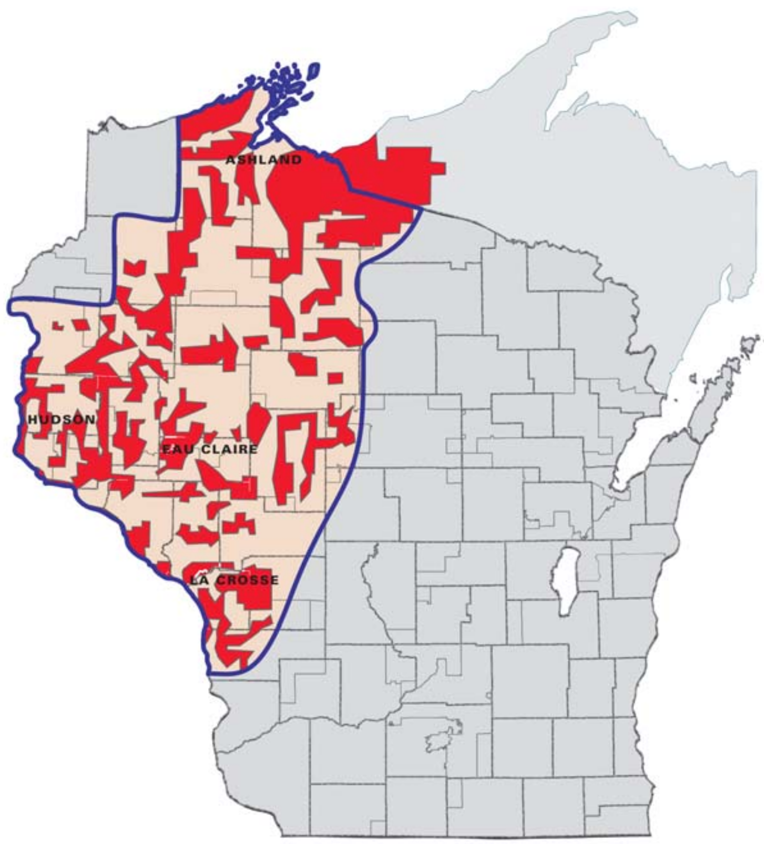
(1) Amounts Billed to Affiliates - Generally represents Operating and Maintenance or Capital expenses provided by NSP Wisconsin for the benefit of an affiliate.

Amounts Billed from Affiliates - Generally represents Operating and Maintenance or Capital expenses provided by the affiliate for the benefit of NSP Wisconsin.

Other - Generally represents the net convenience payments and inventory transfers made between NSP Wisconsin and affiliates. A debit balance indicates a receivable, meaning that NSP Wisconsin made more convenience payments and inventory transfers for the affiliates than the affiliates made for NSP Wisconsin.

Net Intercompany (Payable) Receivable - Generally represents the net amount due to NSP Wisconsin by the affiliate (a debit balance) or the net amount owed to the affiliate by NSP Wisconsin (a credit balance) for all transactions occurring in the year.

Xcel Energy®



ELECTRIC SERVICE TERRITORY-COUNTIES SERVED

*Xcel Energy offices located in cities listed below

WISCONSIN ELECTRIC SERVICE TERRITORY - COUNTIES SERVED

Ashland County
*Ashland

Barron County
*Rice Lake

Bayfield County
*Bayfield

Chippewa County
*Chippewa Falls

Clark County
*Neillsville

Crawford County

Dunn County
*Menomonie

Eau Claire County
*Eau Claire

Iron County

Jackson County

La Crosse County
*La Crosse

Lincoln County

Marathon County

Monroe County
*Sparta

Oneida County

Pepin County
*Durand

Pierce County

Polk County
*St. Croix Falls

Price County

Rusk County

St. Croix County
*Hudson

Sawyer County
*Hayward

Taylor County

Trempealeau County

Vernon County

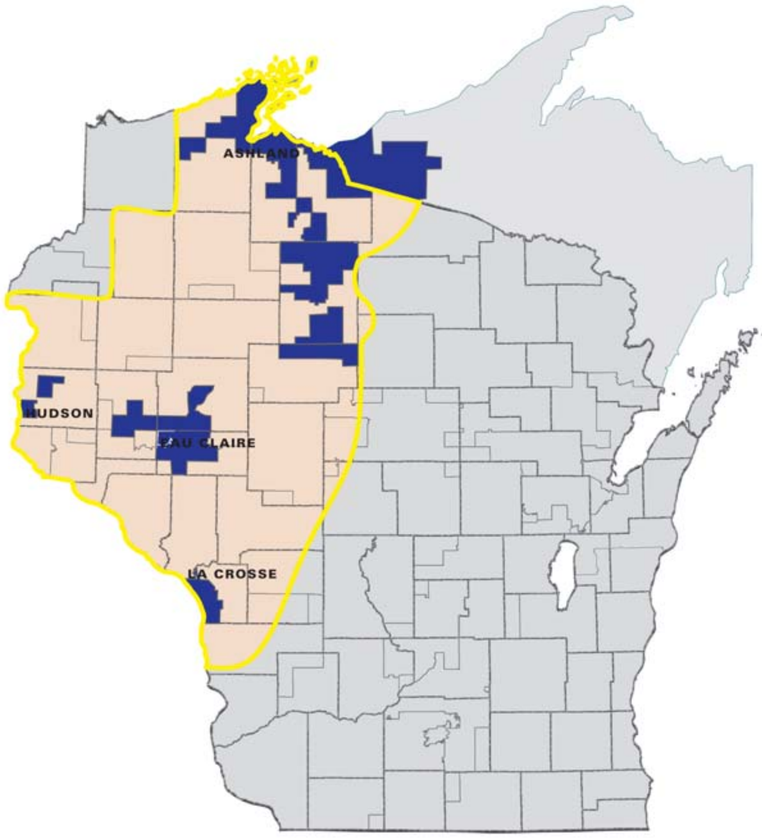
Vilas County

Washburn County

MICHIGAN ELECTRIC SERVICE TERRITORY - COUNTIES SERVED

Gogebic County
*Ironwood

Ontonagon County



NATURAL GAS TERRITORY-COMMUNITIES SERVED

WISCONSIN NATURAL GAS SERVICE TERRITORY

Ashland County
Ashland, Butternut, Gingles, Jacobs, Mellen, Morse, Sanborn

Bayfield County
Barksdale, Bayfield, Bayview, Eileen, Hughes, Iron River, Russell, Washburn

Chippewa County
Chippewa Falls, Eagle Point, Eau Claire, Hallie, Lafayette, Wheaton

Dunn County
Elk Mound, Menomonie, Red Cedar, Tainter

Eau Claire County
Altoona, Brunswick, Eau Claire, Fall Creek, Lincoln, Pleasant Valley, Seymour, Union, Washington

Iron County
Carey, Hurley, Kimball, Montreal, Pence, Saxon

La Crosse County
Campbell, Greenfield, Holland, Holman, Medary, La Crosse, Onalaska, Shelby

Monroe County
Fort McCoy

Price County
Eisenstein, Elk, Fifield, Hill, Lake, Ogema, Park Falls, Phillips, Prentice, Worcester

St. Croix County
Hudson, New Richmond, North Hudson, Richmond, Stanton, Star Prairie, Troy

Taylor County
Rib Lake, Westboro

MICHIGAN NATURAL GAS SERVICE TERRITORY

Gogebic County
Bessemer, Ironwood, Wakefield

Ontonagon County
Bergland, McMillan


ASHLAND
IRONWOOD
HAYWARD
PHILLIPS
RICE LAKE
AMERY
MINNEAPOLIS
HUDSON
CHIPPEWA FALLS
MENOMONIE
ABBOTSFORD
EAU CLAIRE
SPARTA
LA CROSSE
MADISON